APPROACHES TO COST MINIMIZATION OF POWER SYSTEMS WITH DISTRIBUTED GENERATION

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PAPERS WRITTEN ARISING FROM WORK IN THIS THESIS

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C.S. Chang, Li Wei, “Generation Dispatch of Deregulated Energy Resources Using Stochastic Modeling,” the International Federation of Automatic Control (IFAC) Symposium on Power Plants and Power Systems Control (PP & PSC) 2003, Seoul, accepted for presentation.

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SUMMARY

Utility restructuring, technology evolution, an expanding power market, and environmental policies are providing the impetus for the growth of distributed energy resource (DER) into an important energy option. Advanced technologies, deployed in different categories of DERs, endow these dispersed generators with numerous salient advantages and make them competitive in power generation. DERs are playing an increasingly vital role in the restructuring environment and benefit many stakeholders: the utility, independent power producers, and electricity consumers. In order to achieve technical and economic benefits, some DERs are clustered together to form microgrids, power parks, or virtual utilities. Through advanced control and communication, these integrated DERs are more controllable, flexible, and competitive. Recent years have seen a quick and steady increase of DER generation capacity in many countries.

As DERs have an escalating economic impact on the power system, the conventional utility cost minimization algorithms developed for the non-DER environment should be modified to take into account the involvement of DERs. This research aims to meet this challenge. In this thesis, two enhanced overall cost minimization approaches are developed for the hybrid generation environment.

The first approach is the Iteration Approach. In this approach, a multi-objective framework is set up consisting of three modules, namely, utility module, individual DER

module, and individual customer module. While the utility seeks minimum overall generation cost, the DERs focus their attention on maximizing individual profits. These different objectives are achieved within their respective modules. Coordination between the utility generators and DERs is maintained by iterative calculation. This approach guarantees minimum overall cost with the involvement of DERs. However, this approach is computationally intensive.

The second approach, the DER Integration Approach, is more computationally efficient. First, a stochastic model is developed to integrate DERs having homogeneous cost characteristics into virtual utilities. Next, the conventional economic dispatch and unit commitment algorithms are modified to accommodate these integrated virtual utilities. Finally, the solution of these modified algorithms gives the minimum overall cost of both utility generators and DERs. Unlike the first approach, this approach also takes into account the availability of the DERs.

These two approaches, along with a conventional non-DER approach, have been applied on a test system. Comparisons of these resulting minimum generation costs confirm the positive economical impact of DERs on the system. After introducing DERs into the system, the utility reduces its cost; DER operators make profits; and the demands of consumers are satisfied. All the parties benefit from the involvement of DERs in the generation competition.

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Chapter 1 INTRODUCTION

The first part of this chapter provides the background information of this research. Power system restructuring, the fast boost of distributed energy resources (DERs), and the different targets of DER and utility are discussed in the chapter. Secondly, the objective of this research is listed. Lastly, the organization of the thesis is given.

1.1 BACKGROUND OF THE RESEARCH

1.1.1 The Ongoing Industry Restructure

The electric power industries in many parts of the world are undergoing widespread restructuring. These restructuring primarily involve a transition from vertically integrated monopolies to competitive open-market systems [1].

In many developed countries, energy marketplaces are completely deregulated by unbundling the original vertically integrated monopolies. Utilities in these countries experience the segregation of generation, transmission and distribution into independent competitive commercial entities. The generation of utilities is split up into a number of smaller independent competing generating companies (gencos). New independent power producers are welcomed to participate in the generation. The segregation of transmission and distribution creates numbers of new geographically separated transmission companies (trancos) and independent distribution companies (discos) [2].

In developing countries, the electric power industries are in different evolution stages of the open energy market. Some utilities are experiencing re-regulation. In these countries, the lack of investment makes the reinforcement of the infrastructure lag far behind the soaring increase of the load demand. Generation competition from independent power producers is encouraged for the purposes of reducing the heavy burden on utilities and postponing of bulk investment. The industry restructuring also allows the customer more freedom than ever before, to choose an energy provider, method of delivery, and ancillary service [3].

1.1.2 DER on Rapid Rise

Distributed energy resource (DER) generally applies to relatively small generation or energy storage units, scattering throughout a power system, to provide the electric power at or near consumer sites. Presently a number of DER categories exist. A wide variety of technologies have been applied to these different categories, covering both the improvement of conventional technologies as well as innovative new approaches. The gas turbine generator, which evolved from aircraft or truck engines, and the solar cell, which adopts the latest in photovoltaic technology, are two good examples.

Deployed with advanced technologies, DERs are economically competitive and play an important role in the restructuring environment. Furthermore, the emergence of microgrids, power parks, and virtual utilities extends the distributed generation(DG) concept by encompassing several DERs linked together using advanced sensor, communication, and control technologies. These integrated DER clusters are more controllable, flexible, and competitive compared with single DER unit [4].

Because of increasing demands, the energy industries are facing two main challenges: inadequate generation and bottlenecks in the transmission and distribution infrastructure.

Although the former can be solved by the expansion of utility generation capacity, DER provides a satisfactory solution for both.

Utility restructuring, technology evolution, increasing demands, and environmental policies are providing the impetus for DER's growth as an important energy option. In many countries, DERs are experiencing a rapid rise. Data from an internet source shows that up to 2002, there are about 30~60 GW of DER in U.S, accounting for 4~8 percent of total electricity generating capacity [5].

As DERs play an increasingly vital role in the new restructuring environment, they benefit many stakeholders. Electricity consumers can achieve a lower cost of power as well as improved reliability and additional security of supply. Utility can use DERs to defer expansion of the transmission and distribution infrastructure, reduce power system losses, and enhance system reliability. Independent power producers can elect to add renewable energy to their portfolio where it can offer emissions credits, fuel security, and enhanced marketing value. Energy service companies can install DERs at customer sites and sell services such as reliability and heat (cogeneration) along with traditional electricity to create a new revenue stream. Finally, the society as a whole stand to benefit from having a less centralized power system that is more resistant to natural and man-made disasters, such as an earthquake or a war.

1.1.3 Different Targets of Utility and DERs

The ongoing re-regulation of generation represents the first step towards departing from the centralized paradigm, while the emergence of microgrids, power parks, and virtual utilities represents the second. The non-DER power system is evolving into a hybrid generation environment. In accordance with their independent incentives, these integrated DERs will develop their own independent operational standards, which will significantly affect the overall operation of the power system. In other words, the power system will be operating according to dispersed independent targets, not a coordinated global one. The previously strictly hierarchical system is partially stratified into two layers as below [6].

The upper layer macrogrid is the high voltage meshed power grid, macrogrid. A limited set of large utility generators are under the control of a centralized control center. Through it, the utility commit and dispatch its units coordinately to achieve its target of the overall cost minimization, and maintain the energy balance and power quality.

In the lower layer, local DER-clustered entities control the DERs jointly within the entity to meet end-user requirements for energy, maintain power quality and reliability, and above all, make profits. These entities such as microgrids, power parks, or virtual utilities, are owned or leased by independent power producers, end-users, or utilities. In most cases, they are profit-making entities. Unlike utilities, these operators consider the individual benefits as their economic targets, regardless of the overall system benefits. Therefore, they will ignore dispatch from the centralized control center, but be sensitive to the buy-back electricity prices. The outputs of the DERs will be decided separately by these independent operators.

Due to the ongoing system restructuring and the rapid increase of the DER generation capacity, DER is starting to have a remarkable effect on system operations. Conventionally, to achieve the minimum cost target, utilities used to optimally allocate forecasted load demands among utility generators only. As DERs pour a large amount of electricity into the system, utilities have to revise its dispatch plan and reduce their allocated output in order to maintain the energy balance. As a result, the outputs of utility generators deviate from the preset optimum solution and the utilities' minimum cost target is hence compromised. This calls for new approaches to achieve system's minimum overall cost taking into consideration the involvement of DERs. However the implementation of the new approaches will not be straightforward because of the different targets between the utility and DERs, as discussed above.

1.2 OBJECTIVE OF THE RESEARCH

In a non-DER system, utility cost minimization is achieved through economic dispatch and unit commitment algorithms. As DERs become an important option of generation, conventional utility cost minimization algorithms need to be modified to cater for the hybrid generation environment. The involvement of DERs has to be considered in the new solutions. The objective of this research is to meet this challenge. In this thesis, two enhanced approaches to the overall cost minimization problem are developed and applied on a test system. The conventional non-DER approach is also applied on the same test system. Minimum overall costs are worked out using these different approaches and the results are compared. The comparison of the results shows that DERs yield lower minimum overall costs than that of the non-DER system. This clearly demonstrates the positive impact of DERs on power systems.

The first approach, the Iteration Approach, sets up a multi-objective framework consisting of three modules. The different objectives of utility, DER, and customer are achieved within the respective modules. Coordination among them is maintained by iterative calculation. However, this approach is computational intense. It is presented in Chapter 3.

A second approach, namely the DER Integration Approach, is explicated in Chapters 4 to 7 for its computational efficiency. In this approach, a stochastic model is established to integrate DERs into virtual utilities. Modified economic dispatch and unit commitment are set up and applied to accommodate these virtual utilities. Solving them gives the minimum overall cost of both utility generators and DERs. This approach also takes the availability of DER into account.

1.3 ORGANIZATION OF THE THESIS

This thesis is organized into 8 chapters, which are briefly described as follows:

The first chapter, the introduction, provides the background information of this research. Power system restructuring, the fast and steady boost in DER generation capacity, and the different targets of utility and DERs are discussed in the chapter. Also involved in this chapter is the objective of this research. Chapter 2 gives an overview of the distributed generation concept, including DER, microgrid, power park, and virtual utility.

Chapter 3 explicates the Iteration Approach developed by this thesis. Case studies are given for a quantitative assessment of this approach.

Chapters 4 to 7 elaborate on the DER Integration Approach, which is computational more efficient. Chapter 4 explains a stochastic model to integrate DERs with homogenous cost characteristics into virtual utilities. Chapters 5 and 6 describe how the conventional economic dispatch and unit commitment, respectively, are modified to accommodate these integrated virtual utilities. In Chapter 7, case studies are applied and results of different approaches are compared and discussed.

Finally, Chapter 8 summarizes the conclusions of this research and provides recommendations for the scope of future researches.

Chapter 2 OVERVIEW OF DISTRIBUTED GENERATION

DERs are playing an increasingly important role in the restructuring environment. Widespread deployment of fully integrated DERs further enables advanced operating concepts, such as microgrid, power park, and virtual utility. Though these advanced concepts are presently not practical or viable for large scale application, they hold the potential for providing the high reliability, quality, security and availability of electrical service required by the society in the near future. This chapter draws an outline of the distributed generation concept and gives a survey on these advanced technologies. It begins with a review of DER, followed by introductions to microgrid, power park, and virtual utility.

2.1 DISTRIBUTED ENERGY RECOURSE

2.1.1 Reasons for the Creation and Marketing of DERs

The DER generally applies to relatively small generating units and energy storage units, scattering throughout a power system, to provide electric power needed by consumers. There are several possible reasons for the creation and marketing of DERs [7]:

- Utilities are undergoing widespread re-regulation and de-regulation.
- DERs are dropping in price, and technologies for data communications and control are increasingly intelligent.
- Demand for electricity is escalating globally.
- Regional and global environmental concerns have placed a premium on efficiency as well as environmental performance.
- Customer is allowed to have more choices and concerns have grown regarding the reliability, price, and quality of electric power.

The above-mentioned reasons are defining a new set of power supply requirements that can only be served through DERs in a system of small decentralized power plants situated close to end-users. DERs can supply electricity to a single location, or pump power directly into the regional or national electricity grids [8]. They can be utilized in different applications, including standby power, combined heat and power (CHP), peak shave, grid support, and as a stand-alone system.

2.1.2 Benefits Brought by DERs

Actual benefits of these DER applications can be broken up into three categories as described by U.S. Federal Energy Technology Center (FETC): customer benefits, supplier benefits, and national or general benefits. Some of the prominent benefits are listed here briefly [7] [27].

Customer benefits include:

- Ensuring reliability of energy supply.
- Providing the power quality needed in many industrial applications dependent on sensitive electronic instrumentation and control.
- Enabling savings on electricity rates by self-generating.
- Providing the opportunity for ‘waste’ heat utilization.

Supplier benefits include:

- Limiting capital exposure and risk.
- Avoiding unnecessary excessive capital expenditures.
- Avoiding peak load constraints or price spikes.
- Reducing / eliminating of transmission and distribution charges.
- Avoiding energy line losses.

- Offering a relatively low-cost entry point into a competitive market.
- Opening markets in remote areas without transmission and distribution systems.

National/general benefits include:

- Reducing greenhouse gas emissions by increasingly employing renewable energy resources.
- Responding to increasing energy demands and pollutant emission concerns while providing low-cost, reliable energy.

The most important advantages of distributed generation are its potentials to improve the reliability of the power supply, reduce emissions of air pollutants, and minimize the total generation cost.

Because DER serves power at or near the consumer sites, it can avoid energy congestions in peak time, by supporting all or part of the local demand in the case of transmission or distribution network disruption. Therefore, this can lead to an overall improvement in the power supply reliability, which has become an area of increasing concern as a result of the recent electricity service disruption in many parts of the world. A large percentage of DER harness renewable resources to generate electricity. Compared to other types of generation, they are environmentally friendly and emit fewer greenhouse gases. Taking into account the environment concerns, which may be in the form of an air pollution penalty, these renewable distributed energy resources will become increasingly competitive and have a more important place in the DER family. The potential of distributed generation to minimize the power system cost is the focus of this thesis and will be discussed in the following chapters.

2.1.3 DER Categories

Advanced technologies are applied to different categories of DERs, from mature reciprocating engines to innovative fuel cells. Figure 2.1 illustrates distributions of non-utility net generation of different fuel sources in U.S. in year 2002.

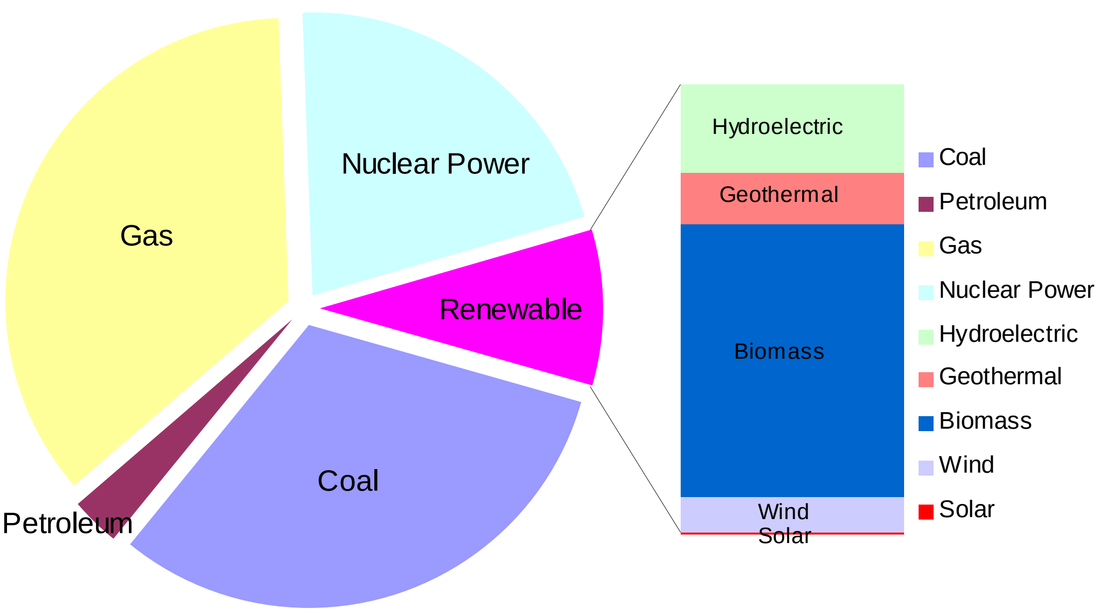

Figure 2.1 U.S. non-utility net generation by fuel source (2002), (U.S. DOE Energy Information Administration).

The characteristics of different DER categories are briefly introduced below.

Reciprocating Engines Distributed Generators

The internal combustion reciprocating piston engines, fueled with fossil, are the oldest type of DER technology, but the most popular type of DER generator in use presently. The two most commonly used reciprocating engines are spark and compression ignition engines. The size of these distributed generators ranges from less than 5 kW to more than 25,000 kW.

Reciprocating piston engines are a proven, mature, but still improving method for distributed generation system. The thermal efficiencies of reciprocating engines can reach as high as 40%. The salient advantages of reciprocating engines are a low-cost manufacturing base and simple maintenance needs. Their disadvantages include a general lack of good “waste” heat for co-generation applications, exhaust emissions, noise, and vibration.

Despite their disadvantages, reciprocating engines are the most popular DER in use worldwide and have tremendous potential for future improvement. They set the performance/cost benchmark that other types of DER must meet to see any significant market success.

Gas Turbine Powered Distributed Generators

Gas turbine generators use a turbine spun by the gases of combustion to rotate an electric generator. Gas turbine generators have distinctly different size, fuel, efficiency, and operating characteristics that in many situations give them considerable advantages over other types of DER.

Gas turbine generators are available in a wide variety of sizes, corresponding to three categories: micro, mini and utility gas turbine generator, as illustrated in Table 2.1. They provide choices of unit rate spanning from less than 25 kVA to more than 265,000kVA. Each category is distinguished not just by size, but by design and operating characteristics unique to its range.

Due to their unique design and size, gas turbine generators have the following characteristics in their market niche [9]:

- Long durability with low maintenance.
- Simple design with a high potential for inexpensive, high volume manufacturing.
- Compact and modular, easy to install and repair.
- Noisy and hence requiring considerable muffling, which reduces output and fuel efficiency.
- Relatively low fuel efficiency compared to other DER types, e.g. reciprocating engines.

Table 2.1 Comparison of gas turbine generator categories [9].

Characteristic	Micro	Mini	Utility
Available range (kVA)	20 – 500	650 – 10,000	12,500 – 265,000
Original design based on	Bus, truck engines	Aircraft engines	Utility needs
Typical fuels	Nat. gas, diesel	Nat. gas, diesel	Nat. gas, fuel oil
Out of service once every	Two years	Eight months	Year and a half
Generator type used	DC with AC conv.	AC sync.	AC sync.
Best fuel efficiency	32%	30%	37%
Can be bought and installed in	A week	Two months	A year or two
Typical cost ($/kW)	$700/kW	$450/kW	$300/kW

Overall, gas turbines are simple, compact, robust, but not outstandingly efficient devices compared to reciprocating engines. However, exhaust heat of gas turbine can be used for co-generation in a waste heat plant. In this case, the overall fuel efficiency of some turbine co-generators is on the order of 60%. This renders the turbines more suitable for installation in close proximity to user sites.

Fuel Cell Powered Distributed Generators

Fuel cells take a unique approach to using fossil fuel for producing electricity. Unlike the reciprocating piston engine or gas turbine, which burns fossil fuel to produce motion to drive a generator, the fuel cells oxidize hydrogen in a fossil fuel in a chemically controlled (catalyst-driven) process. According to the chemical basis for their operation, fuel cells fall into five categories. Ranked in ascending order of internal temperature, they are: proton exchange membrane fuel cells (PEMFC), alkaline fuel cells (AFC), phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), and solid oxide fuel cells (SOFC).

The unique approach of burning fossil fuel offers fuel cell several advantages over rotating fossil fuel generation. They are: high efficiency, very low noise and vibration, low pollution, easily re-usable heat (exhaust) output, and modular availability and quick installation.

Despite these distinct advantages, there are still some barriers preventing the wide spread of fuel cell application. These include high initial cost, maintenance skill needs, fuel sensitivity, and unproven track record. The high price of fuel cells, as illustrated in Table 2.2, is the main factor impeding their expansion. This issue is being vigorously addressed by many agencies and manufacturers, such as DOE (U.S. Department of Energy), GRI (Gas Research Institute), DOD (U.S. Department of Defense), and EPRI (Electric Power Research Institute). It is predicted that this attention will result in fuel cell cost drops, making them more viable in some situations, by the year of 2005 [9].

Combined with these distinct advantages and disadvantages, fuel cells are the best choice among DER categories in some applications, particularly in those sensitive environments in which noise, vibration, or emissions are a concern.

Table 2.2 Typical fuel cell DER cost compared to representative DERs of other types [9].

Type	Fuel Cell	Micro Turbine	Mini Turbine	Piston Engine
Size(kW)	210	250	750	225
Fuel eff. (%)	43	32	29	38
Cost ($)	336,000	176,000	341,250	115,800
Initial Cost($/kW)	1,600	700	455	515
O&M($/yr)	18,000	2,100	10,000	7,800

Renewable Resource Distributed Generators

Renewable power generation resources can be identified as DER due to their nature of being small, modular, and geographically distributed. They include solar thermal power generation resource, photovoltaic (PV) generation resource, wind-powered generation resource, low-head hydropower system, geothermal system, biomass system, tidal power system, and ocean-current turbine. The motivation to harness renewable resources for electricity generation is seldom to obtain local peaking support or reliability backup, but mostly to obtain 'green' energy production.

Renewable resources power generation systems make far less environmental impacts than fossil fuel and nuclear power generation, but are less cost-effective. Most renewable energy sources are subject to some degree of unpredictability in their energy availability and hence the net power output. To obtain dependable and dispatchable power output, they are combined with some form of energy storage, often in "non-electric" form. Besides, most renewable generation plants have site requirements that constrain their geographical distribution.

Distributed Energy Storage Systems

Application of energy storage can augment DER in three aspects: energy stabilization, ride-through capability, and dispatchability. Classified according to the storage medium, there are three categories of energy storage systems, namely: chemical, electrical, and physical. The chemical energy storage system normally uses a variety of battery technologies, including lead-acid, nickel metal hydride, lithium, sodium sulfur, et cetera. Superconducting magnetic energy storage (SMES) system and capacitors are two technologies used to store energy electrically. Physical means to retain energy include thermal storage, pumped hydro storage, compressed air storage, spinning flywheels, and pumped and compressed fluids.

Energy storage systems always involve trade-offs among a number of factors in performance, the most important ones being storage capacity, power output level, service lifetime, and cost. All these above-mentioned approaches are still not satisfactory in the sense of inexpensive price, sufficient capability, and proven long term durability. However, the capacitor storage for low-energy/high-power applications, and stationary low-speed flywheel systems for high-energy/low-power applications, are believed to have the best potential to meet early 21st century DER system needs [9].

2.2 MICROGRIDS

2.2.1 Concept and Benefits of Microgrid

Microgrid can be described as a distribution system with several types of DERs serving a set of electric loads that are either residential, commercial, industrial, or a combination of any of these three [7]. It extends the distributed generation concept to encompass several DERs linked together using advanced sensor, control, and communication technologies. These clustered DERs could be operated either connected with or separated from the established power system, matching power quality and reliability more closely to local end-user requirements [6]. A microgrid consists of a localized grouping of loads and generation operating under a form of coordinated local control, either active or passive.

At the heart of the microgrid concept is the notion of a flexible, yet controllable interface between the microgrid and macrogrid. Essentially, this interface isolates electrically the internal operations of the microgrid from that of the macrogrid, while maintaining their economic connection. Within the microgrid, the conditions and quality of service are determined by the needs of the customer. Outside the microgrid, flows across the interface are determined by the needs of the wider power system.

Microgrids can offer significant benefits in terms of improved reliability, support for transmission and distribution, greater efficiency through combined heat and power, and power system designs that potentially cost less. Although there is much promise for microgrids, it is not yet clear whether microgrids can emerge as anything other than a niche application or if they will become a significant part of the power system infrastructure.

2.2.2 Hypotheses for Practical Microgrid

The concept microgrid proposes radically different methods for operating the power system. In developing the concept, it was assumed that the legislative barriers for the entry of DERs into the power system have been overcome and that DERs amount to a significant percentage of the total generation mix. The following hypotheses are bases of the expansion of practical microgrid over the next decade [6].

1. DER technologies will improve significantly.
2. Site constraints, environmental concerns, fossil fuel scarcity, and other limits will impede continued expansion of the existing electricity supply infrastructure.
3. The potential for application of small scale combined heat and power technologies will tilt power generation economics in favor of generation based closer to heat loads.
4. Customers will desire to control over service quality and reliability.
5. Power electronics will enable operation of semi-autonomous systems.

2.2.3 Autonomous and Non-Autonomous Microgrids

Depending on whether they are connected to the macrogrid, there are two kinds of microgrid, namely autonomous microgrid and non-autonomous microgrid. An autonomous microgrid is an electrically isolated set of power generators that supply all of the demand of a group of customers. In this mode, the microgrid is a stand–alone grid and serves the customers without an external grid connection. A non-autonomous microgrid is one which is served by DERs but is operating in parallel with the utility. The microgrid produces power while interconnected to the macrogrid and may have energy exchange with the utility system [7].

To set up a successful autonomous microgrid, it will have to include several different types of DERs for the purpose of providing the necessary reliability. Since the utility generation, transmission, and distribution network is a complex system which is very difficult to be imitated by the microgrid with respect to reliability, feedback control, communication, and availability, the autonomous microgrid planner may face certain challenges:

1. An outside source will be needed to help the customer in processes such as synchronization and coordination.
2. Possible system faults necessitate system protection for the microgrid which will require technical expertise to set it up.
3. The system must provide supply and load balance, to maintain stable frequency and voltage.

Overall, the development of an autonomous microgrid will require true engineering analysis to design and implement [28].

In the case of non-autonomous microgrid, many of the challenges of the autonomous microgrid either change or disappear. The utility grid can provide base levels for both frequency and voltage. The customer could go by the utility rules on parallel interconnection and enjoy the following benefits:

1. In the event of random failure of the DERs, the maintenance can be performed offline while the customer is served uninterrupted by the utility.
2. The excess power could be sold back to utility.
3. If the utility has a power outage, the microgrid can disconnect itself from the utility grid and keep on serving its customers in a stand-alone mode.

Besides, utility sees benefits too:

1. The utility can avoid or postpone system improvement projects if DERs are implemented in the non-autonomous microgrid mode.
2. The utility can have new business ventures to design, implement, and operate microgrids.
3. A possible benefit to the utility is the reduction of reactive power needed for unity system operation.

There are many technical and non-technical concerns for the establishment of both autonomous and non-autonomous microgrids. Of the two options, the latter is a more beneficial mode of operation for both the utility and the customer [7].

2.3 POWER PARKS

A related concept currently being promoted by the US Department of Energy (DOE) is the power park - a collection of DERs, linked by a minigrid and incorporating advanced telecommunications, to deliver high quality power and exceptional reliability to consumers. Power parks are collections of optimized DER technologies and processes joined by a minigrid, often by a district energy loop and advanced telecommunications technologies. They are generally grid-connected but intended to operate as power islands [11].

The power park systems are designed to be more energy efficient and environmentally sound by utilizing DERs. Well-designed power parks offer an integrated, lowest cost, reliable system where the operators can match energy generation and delivery energy to end-users through a combination of electric, natural gas, and telecommunications services.

The integration of DER technologies within a power park development can potentially provide a range of synergistic benefits including [11]:

- Energy self-sufficiency;

- End-user power quality and reliability;
- Power system reliability;
- Integration with infrastructure;
- Predictable energy costs; and,
- Environmental benefits.

An example of a power park is a 660 kW wind farm in Kotzebue, Alaska [11]. DOE has worked with a remote Native Alaskan community located north of the Arctic Circle in the design and installation of the wind plant, which supplements electricity produced by an existing 11.3 MW diesel power plant. Although the total capacity of this prototype wind plant is relatively small, it is capable of providing approximately 5~10% of the electricity required by the village, at a cost of nearly 13 cents/kWh, which is about one-third less than the 20 cents/kWh of the Kotzebue diesel plant. The high electricity cost of the local diesel plant is due largely to the great expense of transporting fuel and equipment to these remote sites.

DER technologies deployed in power parks are more efficient and environmentally sound. As an integrated 'systems approach' to delivering power when and where it is needed, power parks are expected to play an important role in a restructured industry, and can improve our energy management opportunities in both the near and long term.

2.4 VIRTUAL UTILITY

New technologies, such as microgrids, and new financial instruments, such as energy options, further allow the creation of a new concept, "virtual utility", which can be defined as a flexible collaboration of independent, market-driven entities that provide efficient energy service demanded by consumers without necessarily owning the corresponding assets [10].

A virtual utility could lease or own several DERs and remotely dispatch them in accordance with its own interests. It responds to external signals, such as buy-back price signals, and remotely monitors and controls the DERs. A virtual utility may also provide other types of services, such as improved power quality or load management. In fact, the DERs and other equipment used to provide services could be owned by other entities and managed by the virtual utilities. Most or all functions necessary for the operation of the virtual utility, such as maintenance, billing, and information technology system, could be outsourced. The virtual utility becomes a metaphor for flexible, customer-oriented energy service provision.

The virtual utility, a distributed approach of generating and delivering electricity, may represent an architectural innovation in the sense that it alters the traditional components used to manufacture electricity and hence alters the nature of the product in a fundamental manner. It minimizes non-value-adding activities (such as excess generation capacity), manufactures electricity on a just-in-time basis, and provides high-value-adding services. These justify virtual utilities as a considerably more advanced form of the currently evolving business model of power utilities [12].

There are several advantages for the hypothetical concept of virtual utility, against utility’s large, central power plant. First, the business can be built up gradually, in response to demand. Second, all DERs can be planned, installed and put into operation far quicker than a large power plant. Third, much less initial capital is needed, and the financial risks are smaller than having one big power plant.

Chapter 3 THE ITERATION APPROACH

For the purpose of studying the economic impact of DERs on the power system, an enhanced approach, the Iteration Approach, is developed in this chapter, to ascertain the system's minimum overall cost with the involvement of DERs. The first part of this chapter explicates the approach's structure, a multi-objective framework. Its software implementation is introduced next. Finally, this approach, as well as a conventional non-DER approach, is applied to a study system. The numerical simulation results are presented, compared and discussed.

3.1 OUTLINE OF THE MULTI-OBJECTIVE FRAMEWORK

All utility generators are dispatched and coordinated by a centralized control center, which makes and executes dispatch plans according to provided load information such as daily load curves. Conventionally, load demands are allocated optimally among utility generators to achieve the utility target of minimum overall cost in a non-DER system.

In the new hybrid generation environment, operators of DERs are profit-oriented entities so that their primary objective is profit maximization. The electricity buy-back price offered by the utility is being monitored by DERs. Given the price, DER operators independently make their decisions on whether to commit their DERs and how much power to generate according to their individual profitability. In this regard, DER operators have dispersed independent targets, which are different from utility's coordinated one.

As DERs get involved in power generation with targets different from the utility's target, a mechanism is necessary to protect the interests and coordinate the operations of both utility and DERs in the hybrid generation environment. For this purpose, a multi-objective framework is established in this chapter with three modules, namely the utility module, the DER module, and the customer module, as illustrated in Figure 3.1. The operations of the utility and DERs are optimized according to their respective objectives within the corresponding modules. The operation information is exchanged and fed back between these modules to adjust and coordinate the operations of the utility and DERs. The interests of all parties are protected within respective modules and the coordination between modules finally results in system overall generation cost minimization.

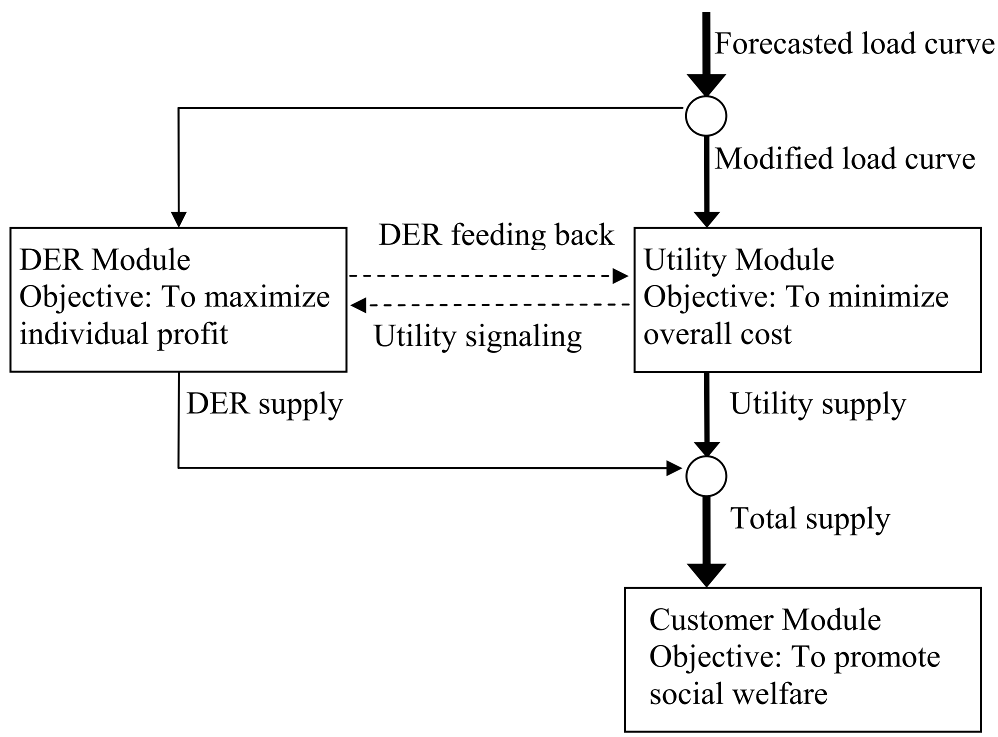

Figure 3.1 A multi-objective framework.

3.1.1 The Formulation of the Utility Module

The utility module aims to protect the interests of utility. The objective of the module is to supply the load demand at a minimum generation cost by optimally committing the utility units and dispatching their outputs. Within this module, only utility units are taken into account.

In a hybrid generation environment, load demands are met by utility generators and DERs together. DER operation is simulated in the DER module. In the utility module, power generation from DERs is assumed temporarily to be a constant at each time interval. After deducting the DER output, the demands to be supplied by the utility are fixed values. Therefore within the module, the problem is simplified into a conventional utility generation cost minimization in a non-DER environment. Defining the total accumulative cost from the first interval to the last interval T as $F_{accu}(T)$, the objective function of the utility module is:

$$\text{Objective function} = \text{Min}\ [\ F_{accu}(T)\ ] \qquad (3.1)$$

This is solved by using the conventional unit commitment and economic dispatch which will respectively be introduced in Sections 5.1 and 6.2.

The inputs of this module include the forecasted load curve, the recent DER power output updated by the DER module, the characteristics of the utility generators, and other algorithm parameters. The task of the utility module is to seek the optimal utility operation state and achieve the minimum generation cost. The module outputs the resulting minimum total cost, the power and cost of each utility generator, and the system lambda at every time interval.

3.1.2 The Formulation of the DER Module

The target of the DER module is to protect DER's interests, i.e. to maximize the profit of individual DER. Unlike utility generators, which are dispatched coordinately by a centralized control center, DERs are controlled separately by a number of independent power producers who focus their attention on individual profits. They are sensitive to the electricity buy-back price offered by utility. Given the price signal of each time interval from the utility, these DER operators make their individual decisions on whether to commit their DERs and how much power to generate to achieve profit maximization.

In the utility module, the outputs of utility generators are constrained by the energy balance constraint. Since DER operators make decisions independently of each other, there is no constraint among the DERs as the utility generators do. This greatly simplifies the solution to the problem: the DERs are treated one by one separately in the DER module. Each DER has its objective function of profit E_j to be maximized. The profit E_j of each DER j is the difference between two cost components: $C_{paid\cdot j}$ which is the revenue received from the utility and $C_{cost\cdot j}$ which is the generation cost of DER j. At each time interval t:

$$E_j = C_{paid\cdot j} - C_{cost\cdot j} \tag{3.2}$$

where E_j is a function of P_j to be maximized. P_j is the power generated by the DER j and sold to the utility. It is subjected to unit generation limits:

$$P_j^{\min} \leq P_j \leq P_j^{\max} \tag{3.3}$$

where $P_j^{\max}$ and $P_j^{\min}$ are the unit's maximum and minimum outputs.

As each DER *j* is paid by the utility at a buy-back price *s*:

$$C_{paid \cdot j} = sP_j \tag{3.4}$$

Determining the cost of a DER technology is often more complex than simply purchasing a piece of hardware at a published price. When considering the adoption of a DER technology, there are other issues to consider. For example, one of them is to determine which technology best fits the specific situation, especially in terms of meeting the energy and environment requirements at an acceptable cost. In this thesis, the model is considered in a scenario of a re-regulated system, in which the lack of generation capacity urges utility to welcome and accept all competitive DERs. To simplify the model, it is assumed that the type of DER technology to adopt has been decided, and only the capital cost, the labor cost, and other expenses related to installing and operating the equipment, are accounted for in the DER generation cost. The DER cost $C_{\cos t \cdot j}$ is expressed as a quadratic polynomial, which is analogical to the utility unit cost.

$$C_{cost \cdot j} = a_{j0} + a_{j1}P_j + a_{j2}P_j^2 \tag{3.5}$$

To maximize E_j:

$$\partial E_j / \partial P_j = 0 \tag{3.6}$$

Solving (3.6) gives the optimum value for P_j:

$$P_j = \frac{s - a_{j1}}{2a_{j2}} \tag{3.7}$$

where P_j is related to s. In cases where P_j is outside its limits, it must be set at the corresponding limit:

$$P_j = \begin{cases} P_j^{\min} & \text{if } \dfrac{s\text{-}a_{j1}}{2a_{j2}} \le P_j^{\min}; \\ \dfrac{s - a_{j1}}{2a_{j2}} & \text{if } P_j^{\min} < \dfrac{s\text{-}a_{j1}}{2a_{j2}} < P_j^{\max}; \\ P_j^{\max} & \text{if } P_j^{\max} \le \dfrac{s\text{-}a_{j1}}{2a_{j2}}; \end{cases} \tag{3.8}$$

Substituting P_j into equation (3.2) gives DER j's maximum benefit as $E(P_j)$. If $E(P_j)$ is negative, decommit the unit j and set P_j to zero. The optimal output P_j^* for DER j is thus expressed as a function of buy-back price s:

$$P_j^*(s) = \begin{cases} P_j(s) & \text{if } E(P_j) > 0; \\ 0 & \text{otherwise;} \end{cases} \quad (3.9)$$

The total power of all DERs can be simply achieved by summing up all the P_j^*.

The inputs of the DER module are electricity buy-back prices at every interval, and the characteristics of each DER units. The model works out the total DER power outputs at every interval and feeds them back to the utility module.

3.1.3 The Customer Module

The objective of the customer module is to promote social welfare. The total consumer welfare can be modeled in the economist's diagram as illustrated in Figure 3.2 [26]. The demand/price curve characterizes how the customer benefits from production processes consuming electricity. The generation/cost curve stands for the generation cost function of the electricity. Accordingly, social welfare can be defined as customer benefit minus generation cost, which reaches its maximum at the intersection of the two curves. To promote social welfare, the energy producer and consumer try to set the load demand at or as close as possible to the optimal point, the intersection [29].

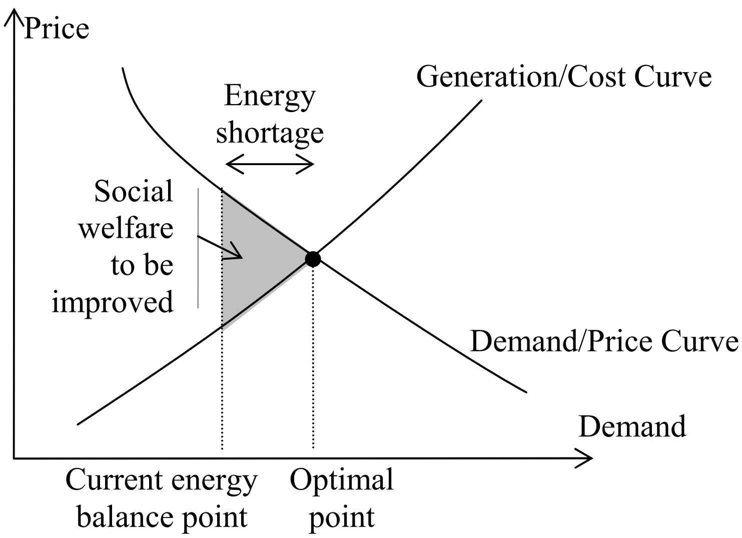

Figure 3.2 Economist's diagram of demand/price and generation/cost curves.

In some developing countries, lack of bulk investment in the electrical industries and soaring electricity demands make energy shortage an increasingly severe problem. Electricity consumers see blackout or brownout, and suffer business losses. Physically, power supply and consumption are balanced at any time as long as the system is not in contingency. Energy shortage essentially refers to the left offset of the current energy balance point from the optimal point in the diagram. The difference between these two points is the amount of energy shortage, which can bring more benefit than cost. The gap between the demand/price and generation/cost curves, shown as the shadowed area in the diagram, provides incentives to attract profit-oriented DERs to participate in power generation. To satisfy consumer's demands and promote social welfare, DERs are brought in to eliminate the energy shortage and set the total power supply as close as possible to the optimal point.

3.1.4 Derivation of the Buy-Back Price

The basic theory of real-time or spot market pricing of electricity was developed by Vickery [13] and Schweppe, et al.[14]. Schweppe and his colleagues developed their price model to include system lambda, as well as other components such as generation and network quality of supply, revenue reconciliation, et cetera. Baughman and Siddiqi introduced reactive power pricing to their model in [15]. More price models were set up using optimal power flow (OPF) to price other system services, such as spinning reserve [16], congestion alleviation [17], and system security [18]. These models which were developed with different purposes result in prices having different compositions. However the system lambda λ, and the loss compensation cost $\frac{\partial P_{loss}}{\partial P_i}\lambda$, are the two common and dominant components of these price models.

The utility will buy back electricity from DERs at a price no higher than the cost to generate the electricity itself. Therefore it will use its generation cost to benchmark its energy trading with the DERs. The cost consists of both operating and capital costs. Since a utility's marginal cost (system lambda) exceeds the average variable operating cost, the difference can be applied towards the capital cost. In the real world, this difference may either over- or under-recover the capital cost. Mechanisms for revenue reconciliation can be set up to compensate for this situation [14]. For simplicity, it is assumed in this thesis that this situation does not happen and the utility's marginal cost tends to recover exactly both utility operating and capital costs. Thus the utility's marginal cost is used as the buy-back price *s* for the energy trading between utility and independent power producers.

$$s = (1 - \frac{\partial P_{loss}}{\partial P_i}) \lambda \qquad (3.10)$$

In (3.10) the loss compensation $\frac{\partial P_{loss}}{\partial P_i} \lambda$ has been taken into account. P_{loss} is the delivery loss and P_i is power output of generator i. As the system lambda varies from hour to hour, the buy-back prices also change accordingly.

3.1.5 The Iteration Mechanism and the Convergence Criteria

As mentioned above, each module in the framework has its individual objective: the utility module simulates utility operation and seeks the minimum utility overall cost; the DER module makes decisions for DER operators for the purpose of profit maximization; the consumer module tries to set the energy balance point at or as close as possible to the optimal point to promote social welfare. This necessitates a mechanism that coordinates the operations of these modules. In the utility module, the load curve information and DER power outputs are inputted from the framework. The results, including the power outputs of utility generators and the system lambdas for every interval, are then worked out. The resulting information flows into the DER module and helps to figure out the DERs' outputs. If the newly achieved DER power outputs do not match the previous ones, the updated values are fed back to the utility module for a new round of calculation. The information of utility and DERs is fed forward and back between these two modules and the iteration will stop at final convergence. The iteration mechanism of data exchange and feedback is provided to ensure optimal and coordinated operation of both the utility and DERs.

The DER module needs the electricity buy-back price to make its generation decision. From the utility module, the hourly system marginal costs, or system lambdas, are worked out. Therefore the time-varying electricity buy-back price s can be derived from the system lambda as explicated in Section 3.1.4 and the expression of s is given in equation (3.10).

In each iterative cycle, the buy-back price s is updated in the utility module and the DER power output ΣP_j is updated in the DER module. Δs and $\Delta\Sigma P_j$ are the respective difference values of s and ΣP_j between two consecutive iterative cycles. The iteration continues until the absolute value of Δs or $\Delta\Sigma P_j$ falls below the pre-specified limits, ε_s or ε_P respectively:

$$\left|\Delta s\right| \leq \varepsilon_s \tag{3.11}$$

or,

$$\left|\Delta \sum P_j\right| \leq \varepsilon_P \tag{3.12}$$

3.2 SOFTWARE IMPLEMENTATION OF THE ITERATION APPROACH

Microsoft Visual C++ 6.0 is chosen for the implementation of the program. The choice is made primarily due to its flexibility and ability to dynamically allocate computation memory during program execution. In C++, pointers can allocate space for variables dynamically and speed up the program execution. Due to the nature of the dynamic programming technique used in the approach, the memory required by the program will increase dramatically as the number of the generation units in a power system increases. Provided a large amount of memory required by a big power system is reserved in the program unchangeably, the computation efficiency will drop as the program solves for a small power system which does not need that much memory. Using pointers can explore the maximum computational ability of this program for a big power system, yet will not affect the computation speed for a small system.

The flow chart of the program is illustrated in Figure 3.3.

In the utility module, the conventional unit commitment and economic dispatch approaches are applied to achieve the minimum utility generation cost. The dynamic programming and lambda iteration techniques are employed in the solution. They are explicated in Sections 5.1 and 6.2.

The detailed algorithm to compute DER outputs in the DER module is elaborated in Section 3.1.2. The expression of the optimal DER output is given in equation (3.9).

In the flow chart, the convergence criteria are discussed in Section 3.1.5. Since implementing the system generation cost minimization in the utility module requires a large amount of computation, the iteration in the flow chart will repeatedly perform these computations, making this approach computationally intensive.

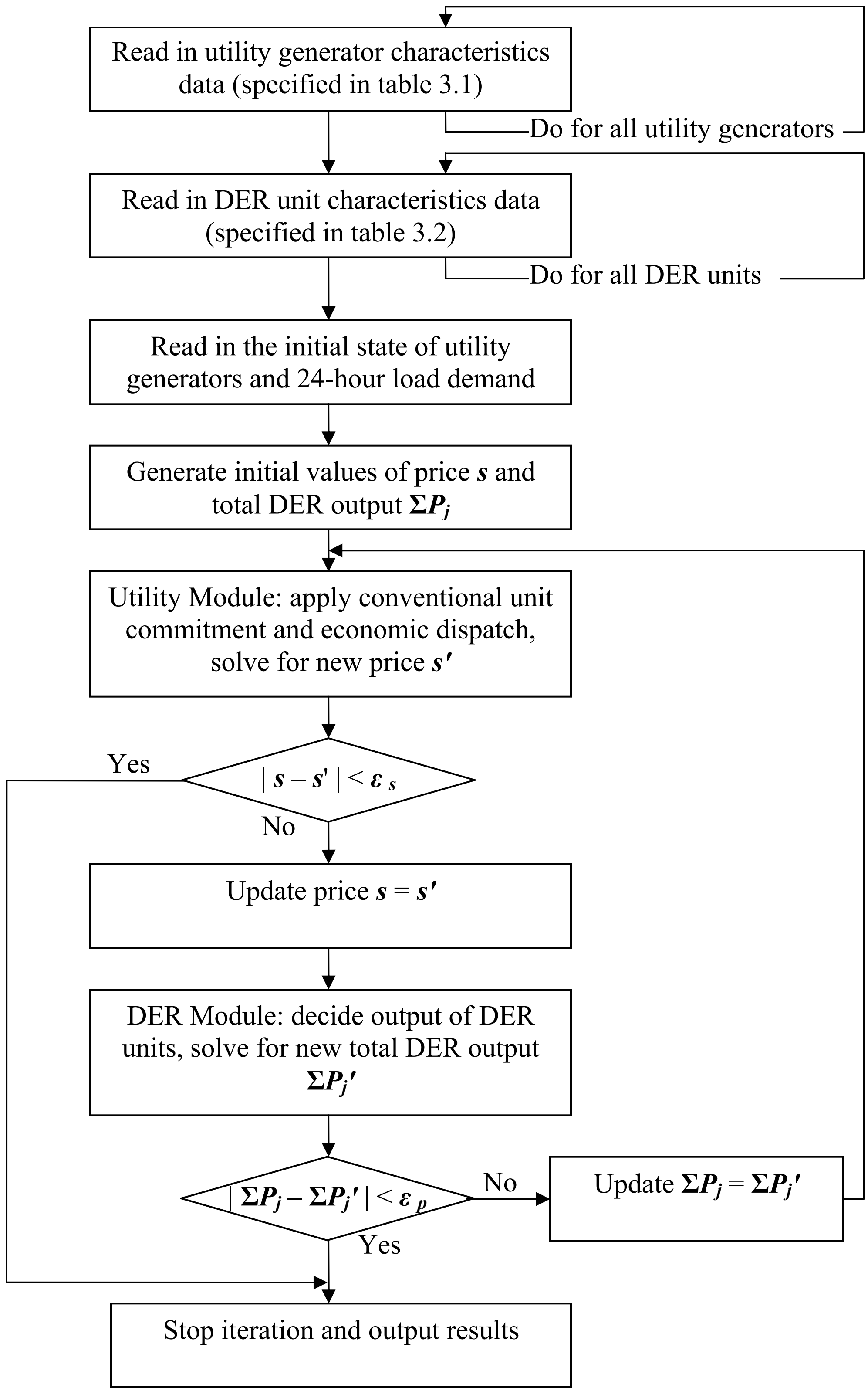

Figure 3.3 Flow chart of the program for the Iteration approach.

3.3 THE STUDY SYSTEM

The program is applied to a study system which has 8 utility generators with the total capacity being 2180MW. The generator characteristics are given in Table 3.1, including minimum and maximum unit capacities, start-up cost, minimum start-up and shut-down times, and coefficients of unit quadratic fuel cost function.

Table 3.1 Characteristics of utility generators.

Utility Unit	$P_i^{\min}$ (MW)	$P_i^{\max}$ (MW)	Start-up cost($)	Min. up time (Hr)	Min. down time (Hr)	a_{i0}	a_{i1}	a_{i2}
Unit1	200	500	10000	8	6	3000	72	0.039
Unit2	100	500	9500	8	6	2000	75	0.042
Unit3	150	350	6500	6	4	3500	78	0.0598
Unit4	50	300	5500	5	3	1500	79	0.059
Unit5	50	250	4000	4	3	2500	82	0.071
Unit6	45	100	2500	2	2	2000	87	0.067
Unit7	50	100	1800	2	2	1000	85	0.078
Unit8	20	80	1700	2	2	2000	99	0.094

One of the DER's merits is its modular availability. There are 6 DER models available in this study system. Their minimum and maximum unit capacities, as well as coefficients of unit fuel cost function are given in Table 3.2. Because DERs are quick units, their start-up and shut-down times are negligibly short compared to utility generators. The start-up cost is also negligibly low. They are neglected in this thesis.

Table 3.2 DER Characteristics.

DER model	$P_j^{\min}$ (MW)	$P_j^{\max}$ (MW)	a_{j0}	a_{j1}	a_{j2}
Model 1	2	8	162.39	84.55	0.0079
Model 2	2	8	153.41	85.05	0.0119
Model 3	2	6	126.63	84.84	0.0201
Model 4	2	5	105.03	87.49	0.0345
Model 5	2	4	86.96	87.39	0.0721
Model 6	1	2.5	57.95	86.39	0.2149

There are 4 virtual utilities in the study system. Each of them may operate one or more different DER models. Table 3.3 gives the DER data of each virtual utility, including the different DER models it has, and the number of DERs for each model. In this approach, generation unit outage rate is not considered, i.e., these DERs are fully available and zero unit outage rate is assumed. These 4 virtual utilities have a total of 29 DERs at a total capacity of 142MW, accounting for 6.1% of the system’s total generation mix.

Table 3.3 DER data of virtual utilities.

Virtual Utility	DER model	Number of DER units
VU 1	Model 1	3
	Model 2	3
VU 2	Model 3	4
VU 3	Model 1	2
	Model 4	5
	Model 5	4
VU 4	Model 4	2
	Model 6	5

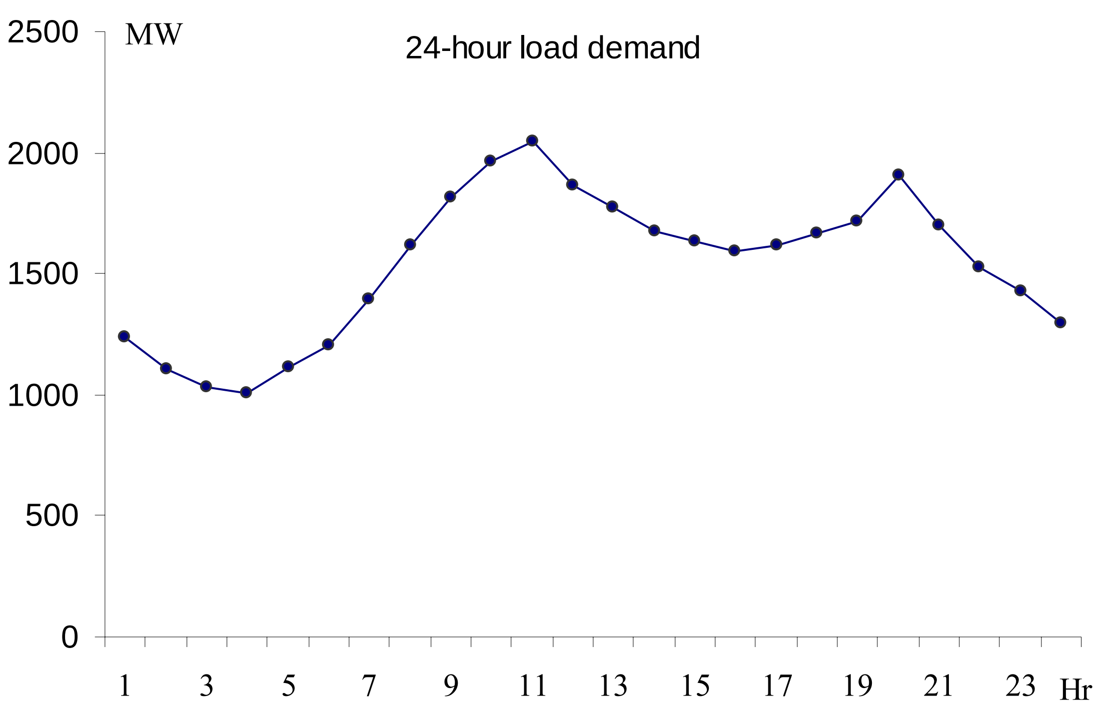

Figure 3.4 A 24-hour load forecast outline

3.4 SIMULATIONS AND RESULTS

To start the simulation, a typical 24-hour load forecast is given as illustrated in Figure 3.4. This daily load forecast has a peak of 2046MW in the daytime and a valley of 1009MW in the late evening and early morning. The daily average load is 1539MW and the load factor is 0.752.

Table 3.4 Initial state of utility generator.

Utility Unit	Initial State	Previous On/Off hours
Unit1	On	10
Unit2	On	10
Unit3	Off	-10
Unit4	On	10
Unit5	Off	-10
Unit6	Off	-10
Unit7	Off	-10
Unit8	Off	-10

The initial states of utility generators are given in Table 3.4. The sign of the unit previous-On/Off-hours indicates that unit's initial state, positive for On-state and negative for Off-state. Its magnitude quantifies the exact hours the unit has been in that particular state. It is set to be 10, greater than all units' start-up or shut-down times, so that all the units are free to start up or shut down at the first interval.

To study the impact of DERs on the power system, this study system is simulated in both a non-DER environment and a hybrid generation environment for comparison. In Case A of a non-DER environment, the load demand is only fed by the utility generators and no DER participates in power generation. Case B encourages generation from both utility and virtual utility in concert to simulate a hybrid generation environment. Delivery losses are not included in both cases.

The program solves for both Cases A and B. It takes the program about two minutes to work out the results of this study systems on a personal computer with a Pentium II processor. In Case B, the program runs for ten iterations before achieving the final results.

In Case A, the minimum utility overall cost is achieved by applying the conventional approaches: unit commitment and economic dispatch. A spinning reserve of 5% is considered. Over the 24-hour period, all the total load of 36932 MWh is served by the 8 utility generators at a minimum overall cost of $3717755. The average cost of generation is $100.66/MWh. The hourly output of each utility generator, along with the overall generation cost and accumulative cost for each hour are summarized in Table 3.5. System lambdas over the 24-hour period are depicted in Figure 3.5.

Table 3.5 Hourly output of utility generator and utility generation, accumulative costs in the non-DER environment (Case A).

Hour	Unit1 (MW)	Unit2 (MW)	Unit3 (MW)	Unit4 (MW)	Unit5 (MW)	Unit6 (MW)	Unit7 (MW)	Unit8 (MW)	Generation Cost ($)	Accumulative Cost ($)
Initial state	ON	ON	--	ON	--	--	--	--		
1	477	407	--	256	--	--	100	--	121461.55	123261.55
2	425	359	--	221	--	--	100	--	107103.07	230364.63
3	395	331	--	202	--	--	100	--	99096.76	329461.38
4	388	324	--	197	--	--	100	--	97148.16	426609.53
5	427	361	--	223	--	--	100	--	107629.72	534239.25
6	465	396	--	248	--	--	100	--	118090.55	652329.81
7	443	376	239	234	--	--	100	--	137634.81	796464.63
8	456	388	247	242	180	--	100	--	161800.36	962265.00
9	500	441	284	280	211	--	100	--	183957.83	1146222.88
10	500	458	296	292	221	100	100	--	201074.69	1349797.50
11	500	458	297	292	222	100	100	77	211483.78	1562981.25
12	500	435	281	276	208	--	100	67	191223.72	1754205.00
13	499	428	275	271	204	--	100	--	179498.97	1933704.00
14	472	403	258	253	189	--	100	--	168401.70	2102105.75
15	462	393	251	246	183	--	100	--	164063.80	2266169.50
16	451	383	244	239	177	--	100	--	159651.83	2425821.25
17	457	388	248	242	180	--	100	--	161908.03	2587729.25
18	470	401	256	252	188	--	100	--	167531.14	2755260.50
19	483	413	265	260	195	--	100	--	172990.33	2928250.75
20	500	437	282	277	209	100	100	--	194096.52	3124847.25
21	452	384	244	239	178	100	100	--	171343.56	3296190.75
22	485	414	266	261	--	--	100	--	152240.11	3448430.75
23	455	387	246	241	--	--	100	--	141702.64	3590133.50
24	414	348	220	214	--	--	100	--	127620.99	3717754.50

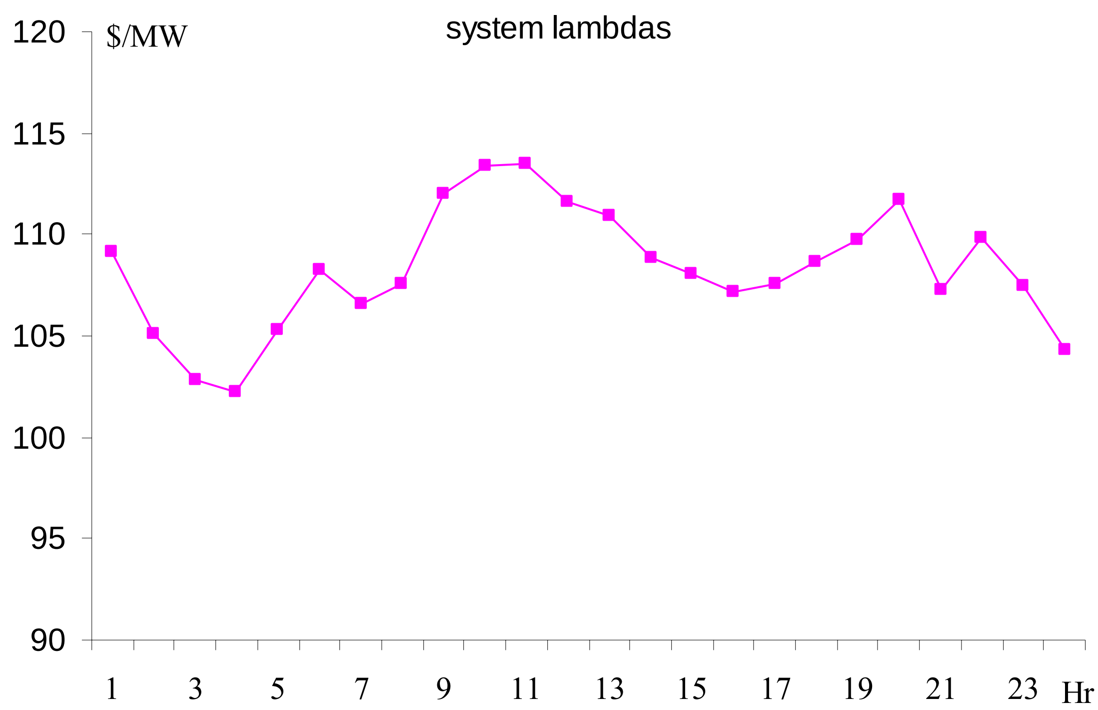

Figure 3.5 The outline of system lambdas for the non-DER environment (Case A).

In Case B, the Iteration Approach is applied to derive the system's generation cost minimization for the hybrid generation environment. With the involvement of DERs, a low spinning reserve of 2% is assumed in this case. This is because DERs are fast-responding generation units and they have short starting and synchronization times. In case the system falls into an emergency situation, these quick-start DERs are able to start up and synchronize in seconds (for those stand-by DERs) or minutes to recover the generation shortage.

Table 3.6 summarizes the final outputs of the utility module, including the hourly output of each utility generator, along with the hourly utility generation and accumulative costs.

Figure 3.6 depicts the profile of the total utility generation over the 24-hour period. The final results of the DER module and the total DER output are presented in Table 3.7 and Figure 3.7 respectively. System lambdas are outlined in Figure 3.8.

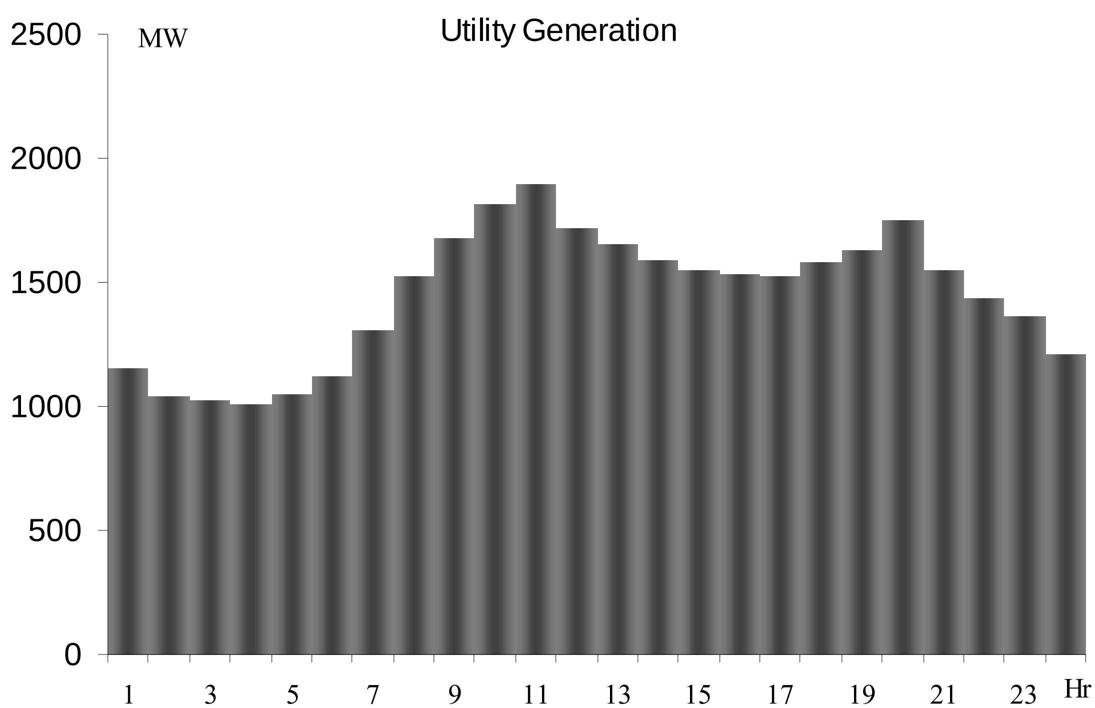

Figure 3.6 Total utility output over 24-hour period in the hybrid generation environment (Case B).

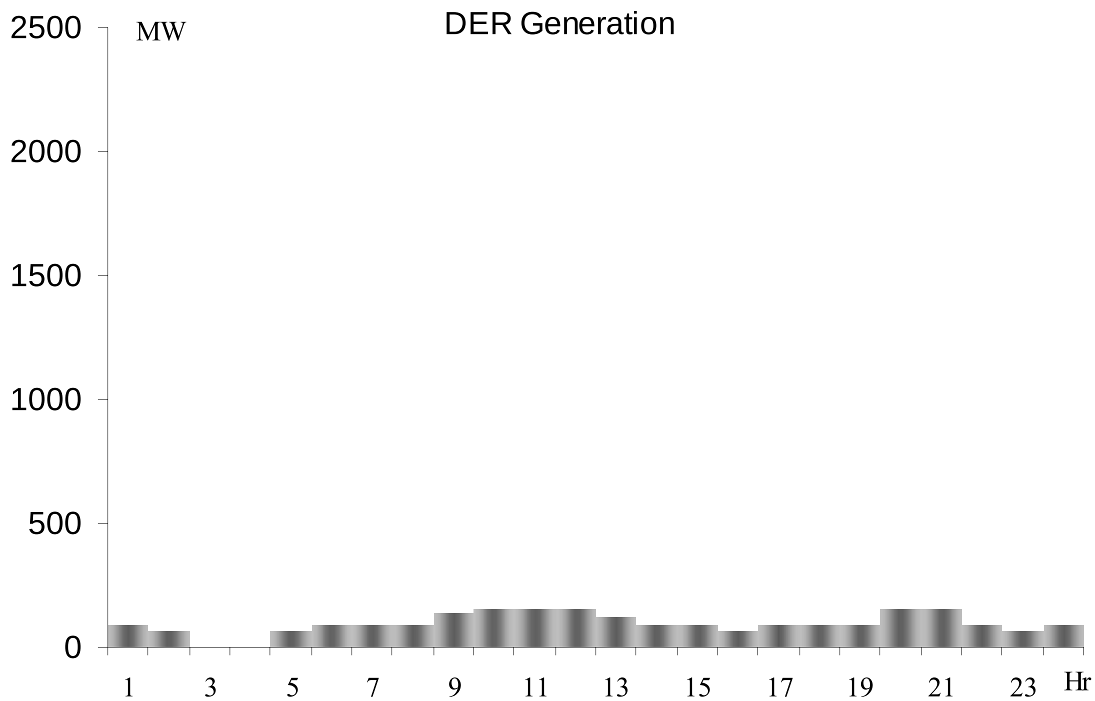

Figure 3.7 Total DER output over 24-hour period in the hybrid generation environment (Case B).

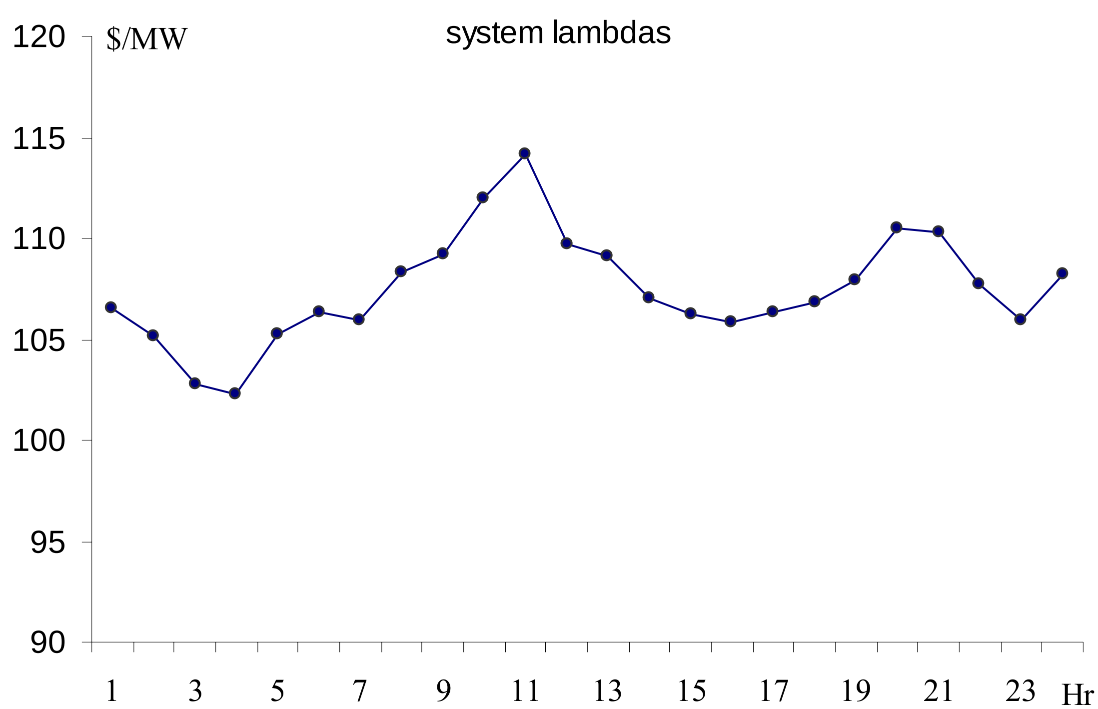

Figure 3.8 System lambdas over 24-hour period in the hybrid generation environment (Case B).

Table 3.6 Hourly output of utility generator and utility generation, accumulative costs in the hybrid generation environment (Case B).

Hour	Unit1 (MW)	Unit2 (MW)	Unit3 (MW)	Unit4 (MW)	Unit5 (MW)	Unit6 (MW)	Unit7 (MW)	Unit8 (MW)	Generation Cost ($)	Accumulative Cost ($)
Initial state	ON	ON	--	ON	--	--	--	--		
1	443	375	--	233	--	--	100	--	111970.09	113770.09
2	400	336	--	205	--	--	100	--	100436.27	214206.38
3	395	331	--	202	--	--	100	--	99096.76	313303.13
4	388	324	--	197	--	--	100	--	97148.16	410451.28
5	402	338	--	206	--	--	100	--	100953.23	511404.50
6	431	364	--	225	--	--	100	--	108683.26	620087.75
7	416	350	221	216	--	--	100	--	128350.88	754938.63
8	485	414	266	261	--	--	100	--	152240.11	907178.75
9	473	403	258	253	189	--	100	--	168619.52	1079798.25
10	500	440	284	280	211	--	100	--	183901.00	1263699.25
11	500	467	303	298	227	--	100	--	192835.98	1456535.25
12	483	413	265	260	195	--	100	--	172825.70	1629361.00
13	467	397	254	249	186	--	100	--	166010.98	1795372.00
14	449	381	243	238	176	--	100	--	158901.73	1954273.75
15	439	372	236	231	170	--	100	--	154637.81	2108911.50
16	434	367	233	228	168	--	100	--	152834.44	2261746.00
17	433	367	232	227	168	--	100	--	152516.72	2414262.75
18	447	379	241	236	175	--	100	--	158047.14	2572310.00
19	460	392	250	245	182	--	100	--	163415.84	2735725.75
20	493	422	271	267	200	--	100	--	177008.69	2912734.50
21	491	420	270	265	--	--	100	--	154384.94	3067119.50
22	458	389	248	243	--	--	100	--	142670.30	3209789.75
23	435	368	234	228	--	--	100	--	134873.66	3344663.50
24	465	396	--	248	--	--	100	--	118090.55	3462754.00

Table 3.7 Hourly output and economic data of virtual utility in the hybrid generation environment (Case B).

Hour	VU1 (MW)	VU2 (MW)	VU3 (MW)	VU4 (MW)	Hourly revenue($)	Hourly cost($)	Hourly profit($)
1	48	24	16	0	9373.68	9238.23	135.45
2	48	0	16	0	6728.56	6695.49	33.08
3	0	0	0	0	0.00	0.00	0.00
4	0	0	0	0	0.00	0.00	0.00
5	48	0	16	0	6738.21	6695.49	42.73
6	48	24	16	0	9355.17	9238.23	116.94
7	48	24	16	0	9326.14	9238.23	87.91
8	48	24	16	0	9528.36	9238.23	290.13
9	48	24	57	10	15180.47	14781.85	398.63
10	48	24	57	22.5	16967.21	16152.03	815.18
11	48	24	57	22.5	17301.70	16152.03	1149.66
12	48	24	57	22.5	16615.74	16152.03	463.71
13	48	24	41	10	13420.42	13035.68	384.74
14	48	24	16	0	9418.72	9238.23	180.49
15	48	24	16	0	9346.31	9238.23	108.08
16	48	0	16	0	6774.92	6695.49	79.44
17	48	24	16	0	9353.56	9238.23	115.32
18	48	24	16	0	9404.25	9238.23	166.02
19	48	24	16	0	9494.78	9238.23	256.54
20	48	24	57	22.5	16734.21	16152.03	582.17
21	48	24	57	22.5	16706.48	16152.03	554.44
22	48	24	16	0	9476.49	9238.23	238.26
23	48	0	16	0	6779.59	6695.49	84.10
24	48	24	16	0	9524.76	9238.23	286.53

Figure 3.7 illustrates that the generation of DERs concentrates on load peak or spike time. A load spike is a sudden and steep load rise lasting for a relatively short time period. The DER's capability of peak and spike shaving promotes economy and security of the system operation, and thus is welcomed by the utility.

DERs are able to shave the load peak because they are encouraged to generate more power as demand is high. Due to the characteristics of utility generation unit, the unit's incremental heat rate increases as the output increases. That is, the marginal generation cost of each unit rises as demand grows. Besides, the utility has to start up a number of less-efficient utility generators to make up the generation shortage. Accordingly at the load peak time, the utility's unit generation cost becomes much higher than that at the mid-peak and off-peak times. This urges the utility to offer higher electricity buy-back price so as to encourage power generation from DERs at peak time.

The DER's capability of spike load shaving is due to its nature of short start-up time and low start-up cost. Starting up large utility generators to cover a load spike is less economic because utility generators have high start-up cost and long compulsory shut-down time. In this case, these small and flexible DERs show their advantages and win the competition. The boost part of spike demand can be largely absorbed by the DERs so that the utility sees a flatter load demand.

As a result, the utility supplies a flatter load curve in Case B than in Case A. Figure 3.6 illustrates that the utility generation peak is now 1894.5MW, lower than 2046MW in

Case A, and the utility load factor is 0.763, higher than 0.752 in Case A. A higher load factor means a flatter load curve.

The final results of the simulations are summarized in Table 3.8. For easy comparison, data from both Cases A and B are listed in parallel.

Table 3.8 The results of simulations for Cases A and B.

Categories	Items	Case A	Case B
Utility	Utility Generation (MWh)	36932	34688.5
	Utility Generation Cost($)	3717755	3462754
	Average Utility Generation Cost ($/MWh)	100.66	99.82
DER operators	DER Generation (MWh)	--	2243.5
	DER Generation Cost ($)	--	236980
	Price Paid by Utility($)	--	243550
	DER profit ($)	--	6570
Overall	Total Load (MWh)	36932	36932
	Total Cost($)	3717755	3699734
	Average Load Cost ($/MWh)	100.66	100.18

In Case B, a big portion of the load demand is supplied by the utility generators and the rest is purchased by the utility from DERs. The cost of utility consists of two parts, the generation cost ($3462754) and the price paid to DERs ($243550). The total cost becomes lower compared to Case A. The utility's saving is $114519884, or 0.31%.

The DERs generate 6.1% of the total 36932 MWh energy demand over the 24-hour period in Case B. Deducting the generation cost ($236980) from the revenue received from the utility ($243550), they make a profit of $6570 at a benefit/cost ratio of 1.028.

From an overall viewpoint, in Case B, the system supplies the demand at a total cost of $3699734, which includes the utility generation cost of $3462754 and the DER generation cost of $236980. It is 0.49% lower than the total cost of Case A. Since the demands in Cases A and B are the same, the lower total generation cost in Case B means that power is generated in a more efficient way and less fuel is burned out in the hybrid generation environment. Social welfare is promoted in this case.

Chapter 4 THE STOCHASTIC MODEL TO INTEGRATE VIRTUAL UTILITY

Another approach to the system overall cost minimization in a hybrid generation power system, the DER Integration Approach, is presented in Chapters 4 to 6. Compared with the Iteration Approach introduced in the last chapter, the DER Integration Approach is computationally more efficient. This chapter sets up a stochastic model to integrate small DER units into large virtual utilities. These virtual utilities can be directly committed and dispatched in the modified unit commitment and economic dispatch algorithms which are presented later in Chapters 5 and 6.

4.1 OUTLINE OF THE STOCHASTIC MODEL

In economic dispatch, a centralized control center dispatches all generators in the system coordinately. Each utility generator adjusts its output according to changes of the system lambda. If the outputs of virtual utilities can be formulated as functions of the system lambda, the centralized control center can control and coordinate the outputs of both utility generators and virtual utilities, by the adjustments of the system lambda. Thus, virtual utilities are involved in the solution to the system overall cost minimization.

Since DERs are owned or leased by profit-making entities, the objective of DER operators is to seek maximum individual profits at given electricity buy-back prices. The output of a DER can thus be modeled as a function of the buy-back price. DERs with homogenous cost and performance characteristics are clustered together to form virtual utilities. The output of a virtual utility is the summation of all its DER outputs and therefore can be expressed as a function of the buy-back price, too. As the buy-back price is a benchmark of the actual power generation cost, it is related to the system marginal cost, or the system lambda. As a result, the virtual utility output can ultimately be formulated as a function of the system lambda.

This chapter presents a stochastic model by which DERs are integrated to form virtual utilities and the outputs of virtual utilities are formulated as functions of the system lambda. The layout of this chapter is introduced below and graphically illustrated in Figure 4.1.

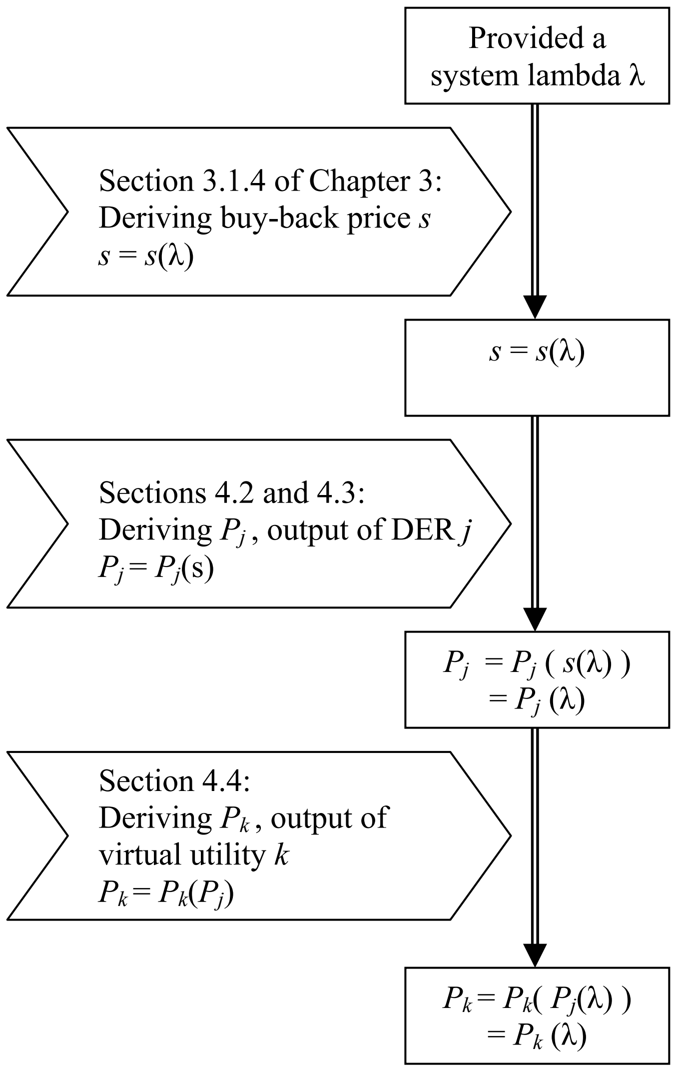

Figure 4.1 Steps of virtual utilities integration.

First, the correlation between the electricity buy-back price and the system lambda is presented in Section 3.1.4. The utility will buy back electricity at the time-varying buy-back price which reflects its real time electricity production cost. As the system lambda is an important index to reveal the utility production cost, the buy-back price can be expressed as a function of the system lambda as illustrated in equation (3.10).

Section 4.2 presents the method each DER uses to determine its optimal output for the purpose of profit maximization. The economic objective of DERs is to maximize their individual profit according to the provided buy-back price. As the DER output is regulated by this objective, its optimal output is a function of the buy-back price, given in equation (3.9).

The random failure events of generator unit are taken into account in this approach and analyzed in Section 4.3. DERs are not fully available all the time because of random failures. Taking into account the DER's availability, the generation of a DER can be modeled more accurately as a stochastic process and its output becomes a random variable.

Lastly, DER with homogeneous cost and performance characteristics are clustered into virtual utilities in Section 4.4. Since the output of the virtual utility is the summation of the outputs of individual DERs, its expectation is a function of the buy-back price. It is further formulated as a function of the system lambda because the buy-back price is decided by the system lambda.

4.2 MODELING OF DER OUTPUT BASED ON PROFITABILITY

While the utility generators are dispatched by a centralized control centre to minimize the overall system cost, DERs are in a different situation. Each plant of DERs is an independent profit-making entity. Its objective is to maximize the individual profit. Consequently, DERs are sensitive to the buy-back price, rather than the dispatch from the centralized control centre.

The objective function of DER j is to maximize its profit E_j, as presented in (3.2). The solution to the objective function is developed in Section 3.1.2. The optimal output P_j^* for DER j is expressed in (3.9), and rewritten here for clarity.

$$P_j^*(s) = \begin{cases} P_j\,(s) & \text{if } E(P_j\,) > 0; \\ 0 & \text{otherwise;} \end{cases} \qquad (4.1)$$

The value of $P_j(s)$ is worked out in (3.8)

4.3 MODELING OF DER AVAILABILITY

Given the buy-back price s, according to (4.1) DER j is expected to generate optimal output $P_j^*(s)$ to ensure its profitability as permitted by availability. However in the real world, a generator random failure will render a DER out of service even if it is profitable at that moment. By considering the failures of DER as random events, a stochastic model of the DER is formulated as below. Taking the forced outage rate $Outrate_j$ from the DER's long-term average availability cycle [19]:

$$Outrate_j = \frac{T_{repair \cdot j}}{T_{avail \cdot j} + T_{repair \cdot j}} = \frac{T_{repair \cdot j}}{T_{total \cdot j}} \qquad (4.2)$$

where $T_{avail \cdot j}$ is the average time available between failures; $T_{repair \cdot j}$ is the average repair time; $T_{total \cdot j}$ $(= T_{avail \cdot j} + T_{repair \cdot j})$ is the mean time between failures, for DER j.

Then the average available rate p_j for DER j is:

$$p_j = 1 - Outrate_j = \frac{T_{avail \cdot j}}{T_{total \cdot j}} \qquad (4.3)$$

Therefore the output of DER j is modeled as a random variable denoted as P_j^R. In this thesis the superscript R of a variable is used to denote that variable as a random variable. P_j^R is subject to Bernoulli distribution as illustrated in Figure 4.2, with the probability density function (PDF) $f_j(P_j^R)$ being:

$$f_j(P_j^R) = (1 - p_j)\delta(P_j^R) + p_j \delta(P_j^R - P_j^*(s)) \qquad (4.4)$$

where $\delta(\cdot)$ is the impulse function.

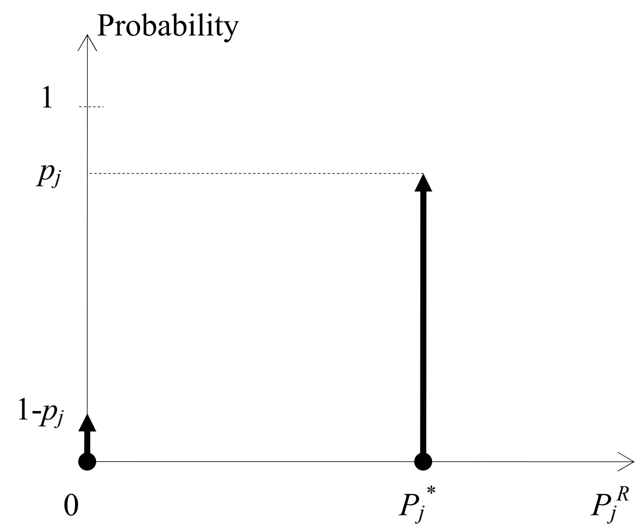

Figure 4.2 PDF of the output P_j^R of DER j.

The mean η_j and variance σ^2_j of P_j^R is expressed as:

$$\eta_j = p_j P_j^* \tag{4.5}$$

$$\sigma^2_j = p_j (1- p_j) P_j^{*2} \tag{4.6}$$

where p_j is given in (4.3) and P_j^* is derived from (4.1). Since P_j^* is decided by s, η_j and σ^2_j are functions of s too.

4.4 INTEGRATION OF DERS INTO VIRTUAL UTILITIES

As discussed in Sections 4.2 and 4.3, DERs with homogeneous cost and performance characteristics are clustered together as virtual utilities to achieve technical and economical benefits. In such a circumstance, the utility can only observe the response of virtual utilities to the buy-back prices. How a single DER in the virtual utility reacts to the price is not 'visible' to the utility. Therefore this section aims to formulate the output of virtual utilities as a function of *s*.

The total output of a virtual utility is achieved by summing the outputs of all DERs in that virtual utility. Each virtual utility k is made up from J_k DERs as follows:

$$P_k^R = \sum_{j \in J_k} P_j^R \qquad (4.7)$$

where P_k^R and P_j^R are respectively the outputs of virtual utility k and DER j. Since P_j^R is a random variable as described in Section 4.3, P_k^R is the summation of random variables. According to the probability theory, P_k^R is also a random variable. This means that the generation of virtual utilities is a stochastic process.

Knowing the probability density function (PDF) of each P_j^R from (4.4) and assuming they are independent of each other, the PDF of P_k^R can be derived by applying a numerical convolution using recursive technique. The recursive technique is detailed in Appendix. The resulting PDF of P_k^R is depicted in Figure 4.3.

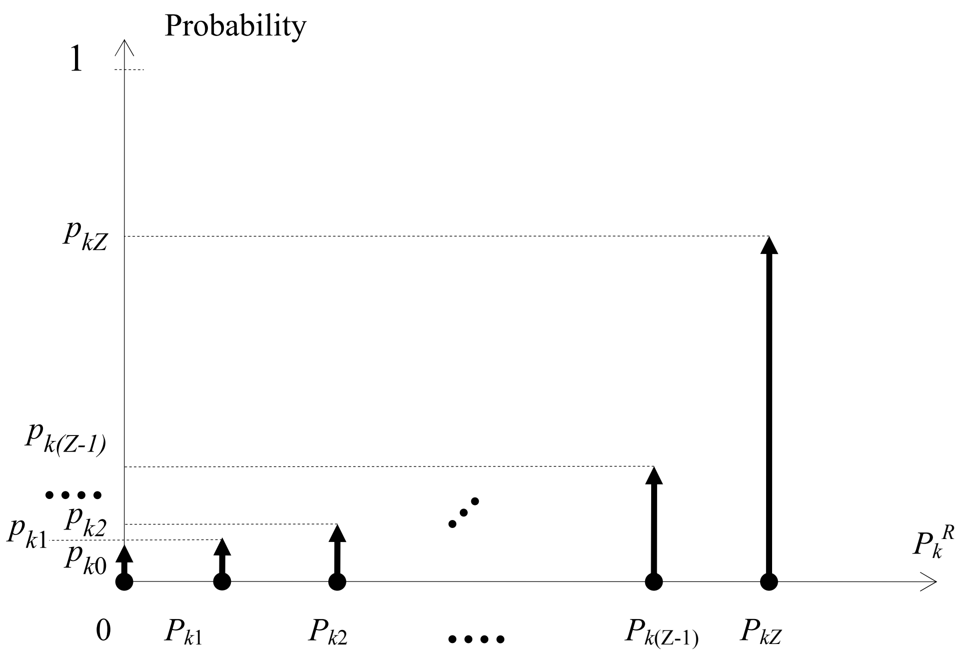

Figure 4.3 PDF of the output of virtual utility k.

The output of virtual utility k has Z possible values. The value of Z is dependent on k, seeing that virtual utilities having different numbers of DERs will have different Zs. As the value of the output is P_{kz}, it has a corresponding probability, p_{kz}. The summation of all the probabilities equals to 1:

$$\sum_{z=0}^{Z} p_{kz} = 1 \tag{4.8}$$

The maximum output P_{kZ} is the total optimal outputs of all DERs, but at a probability p_{kZ} less than 1:

$$P_{kZ} = \sum_{j \in J_k} P_j^* \tag{4.9}$$

From Figure 4.3, f_k , the PDF of P_k^R , is expressed as:

$$f_k(P_k^R) = \sum_{z=0}^{Z} p_{kz} \delta(P_k^R - P_{kz}) \tag{4.10}$$

where $\delta(\cdot)$ is the impulse function. The mean η_k and variance $\sigma^2{}_k$ of P_k^R is achieved as:

$$\eta_k = \int P_k^R f_k(P_k^R) dP_k^R \tag{4.11}$$

$$\sigma^2{}_k = \int (P_k^R - \eta_k)^2 f_k(P_k^R) dP_k^R \tag{4.12}$$

DERs in one virtual utility may share common auxiliary systems: from recuperators to cooling systems. Since they are electrically or mechanically coupled, the output distribution of each DER within one virtual utility is considered to be dependent on each other and the dependence between DERs can be described by a covariance matrix $\{\boldsymbol{\mu}\}$:

$$\{\boldsymbol{\mu}\} = \begin{bmatrix} \sigma_1^2 & \mu_{12} & \cdots & \mu_{1J_k} \\ \mu_{12} & \sigma_2^2 & \cdots & \mu_{2J_k} \\ \vdots & \vdots & \ddots & \vdots \\ \mu_{J_k 1} & \mu_{J_k 2} & \cdots & \sigma_{J_k}^2 \end{bmatrix} \tag{4.13}$$

where σ^2_j is the variance of DER j, and μ_{ij} is the covariance between DERs i and j. From probability theory [20], the mean η_k and variance σ^2_k of the $P_k^R(s)$ are given by:

$$\eta_k = \sum_{j \in J_k} \eta_j \tag{4.14}$$

$$\sigma_k^2 = \sum_{j \in J_k} \sigma_j^2 + 2 \sum_{i \in J_k, j \in J_k, i \neq j} \mu_{ij} \tag{4.15}$$

where η_j and σ^2_j are the mean and variance of DER j respectively, and their expressions are given in (4.5) and (4.6). η_k and σ^2_k are functions of the buy-back price s. Therefore, the expectation of power output of virtual utility k can be expressed as the mean of P_k^R:

$$P_k(s) = \eta_k(s) \tag{4.16}$$

From Section 3.1.4, s is a function of the system lambda λ. Thus the output expectation of virtual utility k is ultimately expressed as a function of λ:

$$P_k = P_k(\lambda) \tag{4.17}$$

That means provided the λ, the expected output P_k of virtual utility k is calculated according to equation (4.17). While the outputs of DERs are determined according to the buy-back prices, their summation, the output of the integrated virtual utility, appears to be 'dispatchable' by the adjustment of λ.

Chapter 5 THE MODIFIED ECONOMIC DISPATCH

The utility operates the power system safely, stably, reliably and economically. The economic objective of the utility is to operate the system at a minimum overall cost. To achieve this, the utility optimally commits utility generators and dispatches their outputs to serve the load demands. The system's overall cost minimization can be described as a nonlinear integer programming problem, subject to different sets of constraints. Traditionally, it involves two stages: unit commitment and economic dispatch [19]. This chapter begins with a brief introduction of conventional economic dispatch, followed by the establishment of a modified economic dispatch which includes the DERs in its enhanced objective function and constraints. Lastly, the computational method of the solution to the modified economic dispatch is presented.

5.1 INTRODUCTION TO CONVENTIONAL ECONOMIC DISPATCH

The efficient and optimum economic operation of electric power generation system is always an important issue in the electric power industry. The utility targets to achieve its minimum overall cost by economic dispatch within a short time period.

In the scope of economic dispatch, it is assumed that all the generators on hand are committed, and the load is economically dispatched among them so that the system's minimum overall cost *F* is achieved. Assume that a system consists of *M* utility units, *F* can be formulated as:

$$F = \sum_{i \in M} C_{\cos t \cdot i} \tag{5.1}$$

where $C_{cost \cdot i}$ is the generation cost of utility generator *i* for generating energy P_i, which can be expressed as a quadratic function:

$$C_{cost \cdot i} = a_{i0} + a_{i1} P_i + a_{i2} P_i^2 \tag{5.2}$$

Seeking the minimum value of *F* for (5.1) is subject to the energy balance constraint:

$$\sum_{i \in M} P_i = P_D + P_{loss} \qquad (5.3)$$

P_D and P_{loss} are respectively system demand and delivery loss. P_i stands for the output from generator i, which is subject to its operating limits:

$$P_i^{\min} \leq P_i \leq P_i^{\max} \qquad (5.4)$$

where $P_i^{\max}$ and $P_i^{\min}$ are unit maximum and minimum output.

(5.1) and (5.3) represent a constrained optimization problem that can be resolved formally using advanced calculus methods that involve the LaGrange function. By introducing undetermined LaGrange multiplier λ, the LaGrange function can be constructed as:

$$\pounds\,(P_i) = \sum_{i \in M} C_{\cos t \cdot i} + \lambda\,\Big(\sum_{i \in M} P_i \;-\; (P_D + P_{loss}) \Big) \qquad (5.5)$$

According to Kuhn-Tucker conditions, the necessary conditions for an extreme value of (5.1) are that the first derivatives of the LaGrange function with respect to each of the independent variables equal to zero [21]. Therefore solving the partial derivative of LaGrange function gives λ, P_i, $C_{cost \cdot i}$, and the minimum value of F.

5.2 MODIFIED ECONOMIC DISPATCH ACCOMMODATING DERS

Conventionally, there is no or negligible DER generation capacity existing in the power system. In economic dispatch, the system demand and delivery loss are served by utility generators only, as introduced in the last section. With the outspread of DERs in distribution networks, the non-DER system evolves into a hybrid generation environment, as illustrated in Figure 5.1. The DER generation capacity has to be taken into account in the new environment. To achieve this, a modification of the conventional economic dispatch is introduced in this chapter.

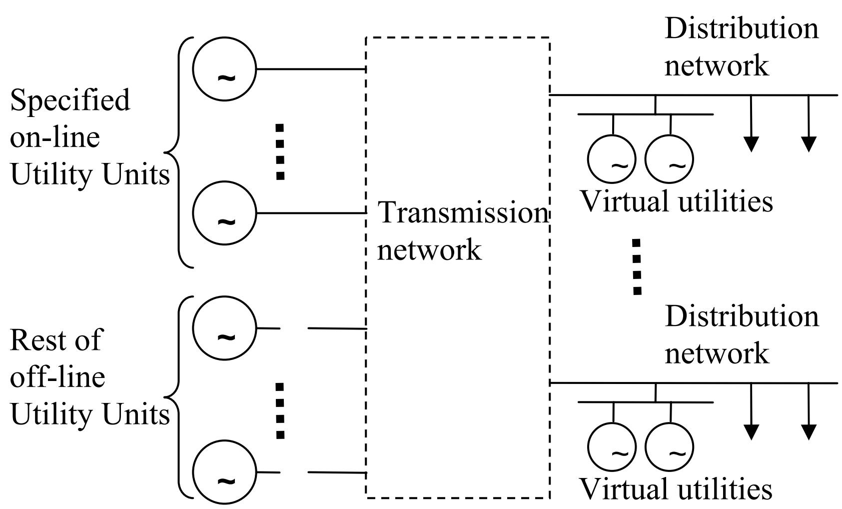

Figure 5.1 The hybrid generation environment with the involvement of DERs.

Assume that all DERs with homogenous cost and performance characteristic in the distribution system are integrated into K virtual utilities. In addition, M utility generators are connected to the system at time interval t. The power balance constraint becomes:

$$\sum_{i\in M} P_i + \sum_{k\in K} P_k = P_D + P_{loss} \tag{5.6}$$

where $\sum_{i\in M} P_i$ is the total power generated by utility generators and $\sum_{k\in K} P_k$ is the total power from virtual utilities. Consequently, the generation cost consists of two parts: the costs for $\sum_{i\in M} P_i$ and $\sum_{k\in K} P_k$. F is obtained by economically dispatching load and delivery loss among these on-line utility generators and virtual utilities.

$$F = \sum_{i\in M} C_{\cos t\cdot i} + \sum_{k\in K} C_{paid\cdot k} \tag{5.7}$$

which includes $\sum_{i\in M} C_{\cos t\cdot i}$, the utility generation cost, and $\sum_{k\in K} C_{paid\cdot k}$, the price paid for purchasing electricity $\sum_{k\in K} P_k$ from virtual utilities. $C_{cost\cdot i}$ is formulated by (5.2), while $C_{paid\cdot k}$ is calculated by:

$$C_{paid\cdot k} = sP_k \tag{5.8}$$

where s is the unit electricity buy-back price.

After accommodating virtual utilities into the economic dispatch, the objective function of F minimization is modified as equation (5.7), which is subject to unit operating limits constraints (5.4) and the new power balance constraint (5.6). Therefore the LaGrange function grows to be:

$$\pounds(P_i) = \left(\sum_{i \in M} C_{\cos t \cdot i}(P_i) + \sum_{k \in K} C_{paid \cdot k}(P_k) \right) + \lambda \left\{ \sum_{i \in M} P_i - (P_D + P_{loss} - \sum_{k \in K} P_k) \right\} \quad (5.9)$$

5.3 COMPUTATIONAL SOLUTION TO THE MODIFIED ECONOMIC DISPATCH

A lambda-iteration method is presented in [19] to solve the conventional economic dispatch problem. Since the new established LaGrange function (5.9) takes into account the involvement of virtual utilities, the lambda-iteration method is modified accordingly by adding a module to calculate total power by virtual utilities, as illustrated in Figure 5.2.

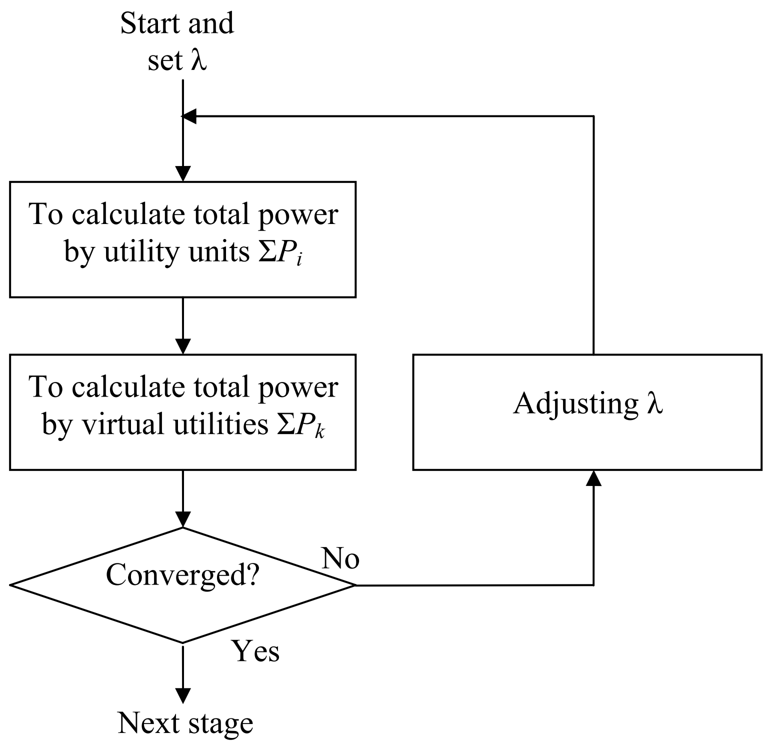

Figure 5.2 Including virtual utilities in lambda searching.

The generation cost F is minimized by successive adjustments of λ as in Figure 5.2. With the current value of λ, each utility unit determines its output P_i by matching its incremental cost rate to λ. Should P_i be out of its operating limits, it is set to the corresponding limit. The method to determine the output of virtual utility is explained in Chapter 4. P_k is calculated as a function of λ, illustrated in (4.17).

In order to check the convergence of the iteration, (5.6) is rewritten in terms of power mismatch Δ_P:

$$\Delta_P = (\sum_{i \in M} P_i + \sum_{k \in K} P_k) - (P_D + P_{loss}) \qquad (5.10)$$

Here load demand P_D is achieved from forecasted load demands, and delivery loss P_{loss} is calculated using "B" matrix loss formula [19]. Recent values of $\sum_{i \in M} P_i$ and $\sum_{k \in K} P_k$ are substituted in (5.10) to update Δ_P. Should the mismatch be outside the tolerance, the iteration continues and λ is adjusted one-step-up if Δ_P is negative, or one-step-down otherwise. The step size $\Delta\lambda$ is halved at every iteration. An example of the first few steps of λ adjustment is demonstrated in Figure 5.3.

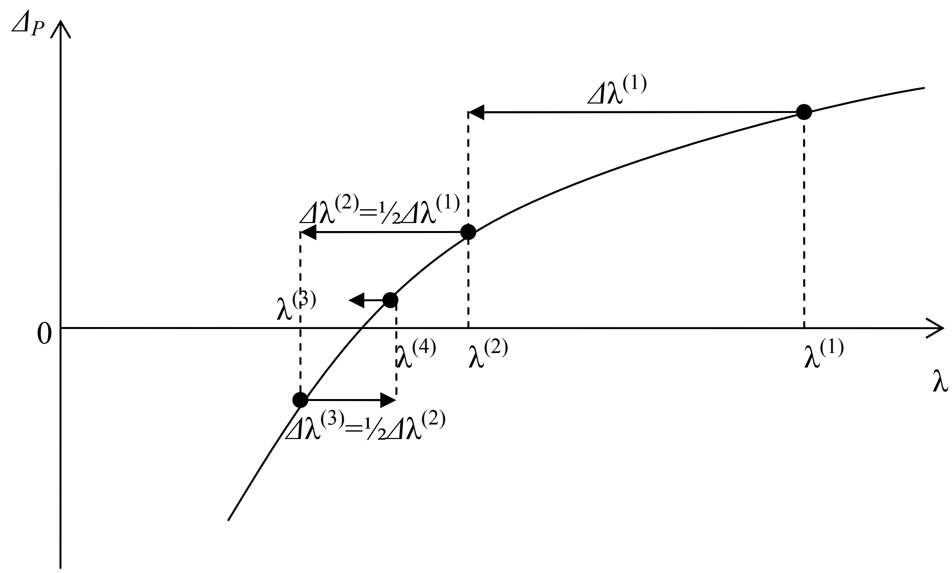

Figure 5.3 λ adjustment.

After successive adjustments, the mismatch finally falls within the tolerance, and the iteration converges. The optimal values of λ, as well as the outputs and costs of utility generators and virtual utilities, are worked out. The minimum overall generation cost F is achieved for the hybrid generation system.

Chapter 6 THE MODIFIED UNIT COMMITMENT

In Chapter 5, a new modified economic dispatch is presented, to search out the system's minimum generation cost in a hybrid generation environment over a short time period. Over a long term horizon, the unit commitment problem should be taken into account. Similarly, to take in the active involvement of DERs, the conventional unit commitment method has to be modified. The first part of this chapter gives an overview of the unit commitment problem. Then a popular approach to the problem, dynamic programming, is briefly introduced. The third part brings in a modified dynamic programming approach to accommodate virtual utilities. Lastly, the computational method of the solution is explained in a flow chart.

6.1 OVERVIEW OF UNIT COMMITMENT

In the scope of economic dispatch, it is assumed that all generation units on hand are committed. However, in reality, this assumption may not be valid over a long time period. In an electric power system, the total demand will generally be higher during the daytime and early evening, and lower during the late evening and early morning. The daily cycle of load demand suggests that it will be more economical to commit just enough generators in accordance with the cycle, rather than all the generators in all time. Therefore the least expensive way to supply the load demands is to commit a subset of all the available generators according to the load curve. The unit commitment decides which subset of generators is to be committed in each period for the purpose of the utility overall cost minimization over a long term horizon.

6.1.1 Unit Commitment Constraints

There are some constraints that need to be taken into consideration in the unit commitment:

1. Adequate generating capacity.

   Enough units must be committed to supply the load.

2. Sufficient spinning reserve in case of unit random failure.

   Spinning reserve describes the total amount of generation available from all units synchronized on the system minus the present load plus losses being supplied [19]. Due to generation units' random failures, sufficient spinning reserve must be allocated among these committed units.

3. Thermal unit constraints.

   Because a thermal unit can undergo only gradual temperature changes, minimum start-up time, minimum shut-down time, start up cost should be considered.

4. Other constraints.

   These include must-run units, fuel constraints, et cetera.

6.1.2 Techniques for Unit Commitment Solution

There are several techniques for the solution of the unit commitment problem. Among them, the most talked-about techniques are Priority-list schemes, Dynamic Programming (DP), and Lagrange relaxation (LR).

Due to its simplicity, the priority-list technique is the traditional technique utilities use to solve the unit commitment problem. The utility predetermines the order by which generator units start up or shut down, based on availability, efficiency, and unit characteristics. This technique relies heavily on prior experience.

The dynamic programming is a commonly used technique in unit commitment, due to the dynamic nature of the problem. For small scale systems, dynamic programming is a sound and robust solution. Nevertheless, because the dimensionality of the dynamic programming algorithm is an exponential function of the variables, it suffers a rapidly increasing computational time as the number of generators increases. In this thesis, all case studies are simulated in a study system, of which the scale is kept relatively small to justify the use of the dynamic programming approach.

The Lagrange relaxation method is based on a dual optimization approach which avoids the dimensionality problems that affect the dynamic programming solution. However other technical problems arise and must be addressed, such as unstable convergence, or no guarantee that the dual solution will stop at a feasible solution.

6.2 INTRODUCTION TO DYNAMIC PROGRAMMING ALGORITHM

The dynamic programming was developed by Dr. Richard Bellman and his associates as a result of the application of digital methods to solve a wide variety of control and dynamic optimization problems in the late 1950s [22]. It started to be applied in the scheduling of power generation systems in the late 1960s. Much of the pioneering work in this area was done by Garver [23]. Researches [24], [25] and [30] further refined the unit commitment solution.

Assume a power system has M utility generation units to supply a given demand forecast over T intervals. At any time interval t, some of the M units are committed and the rest of them are off-line. One combination of these on-line and off-line units is denoted as one system state. In every time interval, there are up to (2^M-1) possible system states, where minus one means that one combination with all M units being off-line is an obviously impossible solution and left out of consideration. Figure 6.1 illustrates the 7 (=2^3-1) possible combinations of generation units, or system states, for a three-generator system.

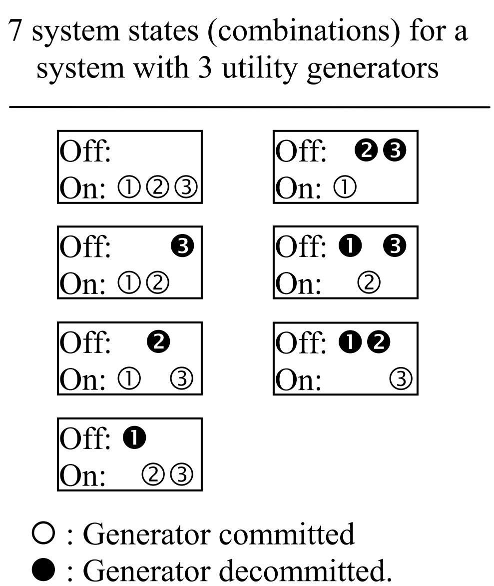

Figure 6.1 The seven possible system states for a system with 3 utility generators.

If one system state is denoted as a node, a state diagram of dynamic programming can be presented as a (2^M-1)*T node square, as illustrated in Figure 6.2. It has (2^M-1) rows for the number of system states per time interval, and T columns for the number of time intervals. The dynamic programming algorithm can thus be graphically interpreted as to find an optimal route from the initial interval to the last interval among the system states in the diagram.

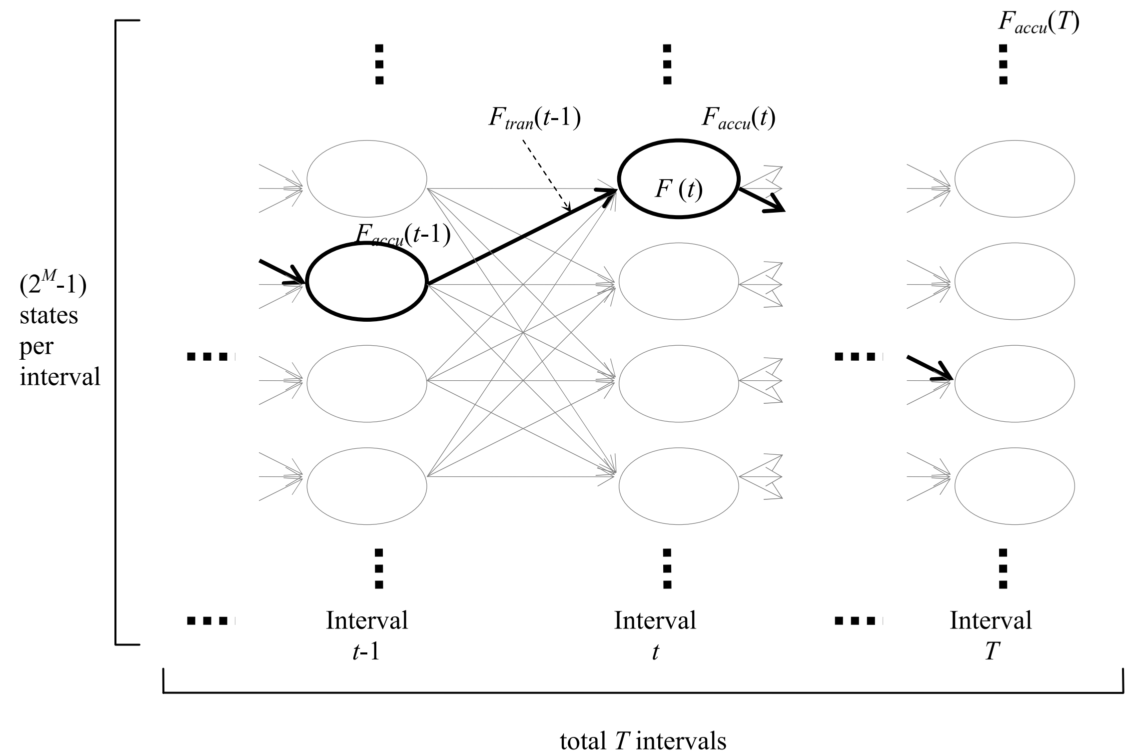

Figure 6.2 System state diagram of dynamic programming.

The forward dynamic programming algorithm searches the route from the initial system state to the last interval step by step. The recursive algorithm to compute the minimum accumulative cost in interval t is:

$$F_{accu}(t) = \min [\ F(t) + F_{tran}(t\text{-}1) + F_{accu}(t\text{-}1)\ ] \qquad (6.1)$$

where $F_{accu}(t)$ is the system's least accumulative generation cost to arrive at interval t. $F_{tran}(t\text{-}1)$ is the transition cost from interval $(t - 1)$ to interval t. $F(t)$ is the generation cost at interval t.

As the forward algorithm recursively compute the $F_{accu}(t)$ to the last interval T, $F_{accu}(T)$ gives the system's minimum overall cost over T intervals.

6.3 MODIFIED UNIT COMMITMENT ACCOMMODATING VIRTUAL UTILITIES

Equation (6.1) is a general formula to solve the system minimum cost problem over a long term horizon. In non-DER environment, only utility generators are considered in the unit commitment. The generation cost and transition cost merely refer to costs incurred by utility generators. As the generation capacity of DER keeps on increasing and now amounts to a significant percentage of the total generation mix, DER should be taken into account in the unit commitment of the new hybrid generation environment.

A straightforward approach may be proposed that each DER unit is treated as one normal generator. Thus they can be included and calculated in the conventional unit commitment by (6.1), just as utility generators are. However this proposal is impractical due to the following reasons.

1. It will dramatically increase the demands on computational resources and time.

Compared to large utility generators, DERs are smaller capacity generation units but with a greater number spreading throughout distribution networks. Considering a system with J DERs and M utility generators, the quantity of DERs may greatly outnumber that of utility units. That is, J is much bigger than M. By simply treating DERs in the same way as utility generators, the system has ($M + J$) generation units. The number of the system states in dynamic programming will increase radically from (2^{M}-1) to (2^{M+J}-1). The sharp increase in computational demands makes this approach impractical.

2. It will be difficult to calculate $F(t)$ in equation (6.1).

$F(t)$ is the total system generation cost of committed generators at interval t. Knowing the specified combination of committed generators, $F(t)$ is worked out by the economic dispatch method. The utility generators are under the control of a centralized control center and thus can coordinately adjust their outputs responding to its dispatch. However DERs are owned or leased by independent profit-oriented entities. They will ignore dispatch from the centralized control center and respond sensitively to the buy-back electricity prices. Therefore it is difficult to coordinate DERs as utility generators in economic dispatch, and to achieve minimum $F(t)$.

To accommodate DERs, the conventional unit commitment is modified. The DERs are specially treated in the modified unit commitment to avoid the above-mentioned difficulties.

Firstly, J DERs with homogeneous cost and performance characteristics are clustered into K virtual utilities as described in Chapter 4. Therefore, the problem to study the impact of DERs on the system now becomes to study the impact of virtual utilities. Noting that K is much smaller than J, the problem is greatly simplified. Regarding a virtual utility as one generation unit, the number of total generators in the system decreases from (M+J) to (M+K).

Secondly, when DERs are integrated to form virtual utilities, the output of a virtual utility is formulated as a function of λ, shown in (4.17). This means that the virtual utility adjusts its output according to the system lambda. Noting that utility allocates load among utility generators by matching each generator's incremental heat rate to the system lambda, the outputs of virtual utilities and utility generators are all dispatchable by the adjustment of the system lambda. In this way, the virtual utilities are coordinated and dispatched, like utility generators, in the economic dispatch. The generation cost $F(t)$, consisting of both costs of utility generators and virtual utilities, is achieved as described in Chapter 4.

Thirdly, all DERs in distribution networks are clustered into K virtual utilities. Adding these virtual utilities into a system with M utility generators means the system states in the dynamic programming algorithm will expand from (2^M-1) to (2^{M+K}-1). This expansion does not make this approach impractical though, it will markedly increase the demands on computational resources and time. To avoid a sharp rise in the number of system states, the virtual utilities are treated as must-run units in the modified dynamic programming algorithm. That means each virtual utility has only one state (On-state). Adding them into the system will not increase the number of combinations of units, or the system states. It remains as (2^M-1) and the dimensionality of the problem stays the same.

For example, a system with 3 utility generators has 7 (=2^3-1) system states. Adding 2 virtual utilities with both On-state and Off-state will increase the number of the system states to 31 (=2^{3+2}-1). However if the two virtual utilities are treated as must-run units, the number of the system states will remain as 7, illustrated as Figure 6.3.

The virtual utilities can be treated as must-run generation units because they are actually integrated by a number of small fast response DERs. Unlike utility generators, their minimum power output is zero and they have negligibly short start-up and shun-down times, as well as low start-up cost.

It may happen occasionally that all the DERs within a virtual utility are unprofitable given a low electricity buy-back price. At that time, all DERs are turned off. There is no power output from that virtual utility. In this case, the algorithm will still regard that virtual utility as an ON generation unit, with zero output at zero cost.

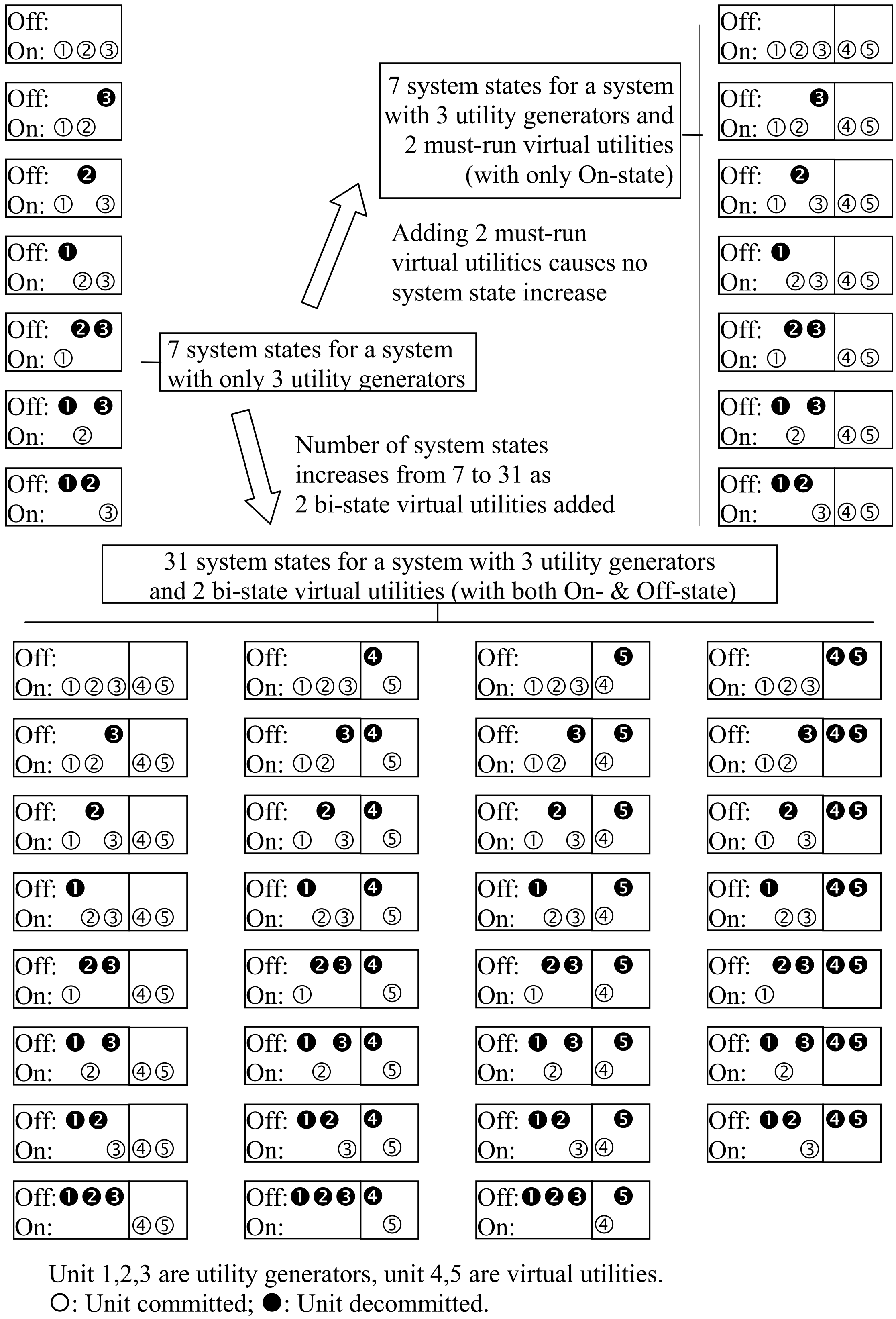

Figure 6.3 Two ways to add virtual utilities into the system.

In this modified dynamic programming, the dimensionality of the problem is decided only by the number of utility generators in the system, regardless of the number of virtual utilities. This approach allows a big number of virtual utilities to be calculated without a large increase in computation.

Table 6.1 gives comparison of the Iteration Approach and DER Integration Approach. The numbers of system states in the two approaches are same, while the DER Integration Approach needs no iteration in its solution. This indicates that the DER Integration Approach is computationally more efficient than the Iteration Approach.

Table 6.1 Comparison of two approaches.

	Iteration Approach	DER Integration Approach
Number of Generation Units	M (= 8) utility generators in the Utility Module, and J (= 28, for DERs with different cost characteristics) DERs in the DER Module	M (= 8) utility generators, and K (= 4)Virtual utilities (integrated by J DERs)
Number of system states for DP algorithm	2^M-1 (= 255) DP algorithm is applied to the Utility Module only	2^M-1 (= 255) the K Virtual utilities are must-run units so that no system state increases
Iteration	Iterative computations are needed to converge the Utility and DER modules	No iteration

6.4 COMPUTATIONAL SOLUTION TO THE MODIFIED DYNAMIC PROGRAMMING

In order to get the system's minimum generation cost over T intervals, the dynamic programming algorithm has to search out the optimal route in the system state diagram and work out the minimum accumulative cost $F_{accu}(T)$ at the last interval T. The objective function is:

$$\text{Objective function} = \text{Min}\ [\ F_{accu}(T)\ ] \qquad (6.2)$$

which can be achieved by applying (6.1) recursively. For clarity, (6.1) is rewritten here.

$$F_{accu}(t) = \min[\ F(t) + F_{tran}(t\text{-}1) + F_{accu}(t\text{-}1)\ ] \qquad (6.3)$$

$F_{tran}(t\text{-}1)$ is the transition cost from interval $(t - 1)$ to interval t, which includes the unit start-up cost. Generator constraints, including unit minimum start-up time and shut-down time, are considered. For instance, if a unit's previous off time is less than its minimum start-up time, it will not be committed and the transition cost from its Off-state to On-state is set to be infinite.

$F(t)$ refers to the total generation cost at interval t. In unit commitment of non-DER power system, this generation cost is only incurred by utility units. As DERs become participants in power generation, part of the electricity is generated by DERs and sold to the utility. $F(t)$ could be literally interpreted as the sum of the generation cost of utility generators and that of DERs. However, the DER generation cost is only known by each virtual utility and inaccessible to the utility when the utility wants to figure out $F(t)$. Although the utility does not know the exact generation cost of each DER, it knows the price paid for purchasing the electricity. From its viewpoint, the utility can alternatively regard the price paid as its cost for the traded electricity. Therefore in this approach, the total generation cost consists of two parts: the utility generation cost for the electricity by utility, and the price paid for the electricity by DERs. $F(t)$ can be achieved by applying modified economic dispatch described in Chapter 5.

This solution starts at the first interval and proceeds forwards to the last interval. In each interval t, $F_{tran}(t\text{-}1)$ is achieved by summing up transition cost of every generation unit and $F(t)$ is calculated by (5.7) as explained in Chapter 5. They are substituted into (6.3) to get $F_{accu}(t)$, the accumulative cost from the first interval till the interval t. The recursive algorithm continues until it reaches the final interval T. $F_{accu}(T)$ is the system's minimum overall cost over the whole time period, taking into account the involvement of DERs. The flowchart is illustrated in Figure 6.4.

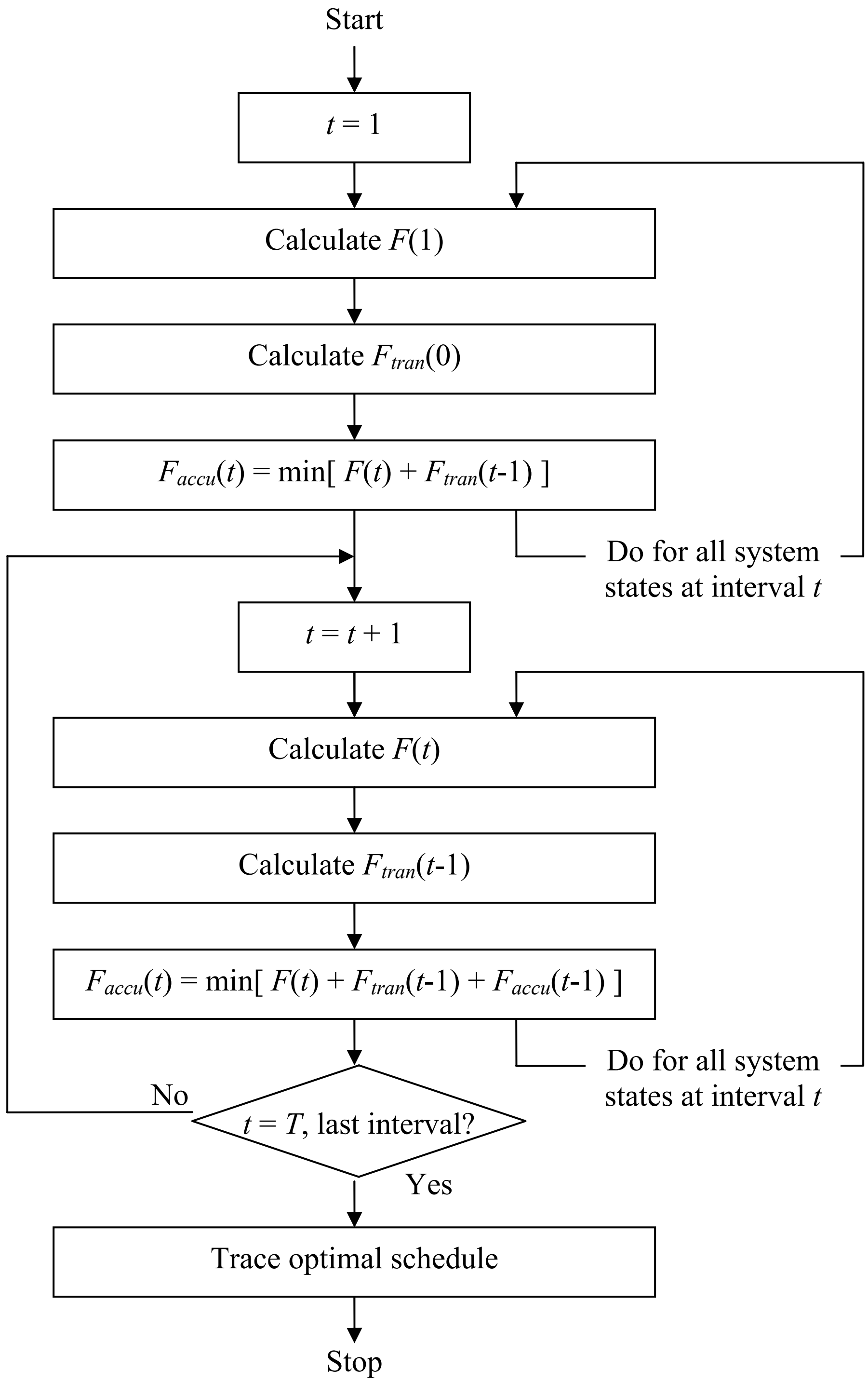

Figure 6.4 Unit commitment via forward dynamic programming.

Chapter 7 SIMULATION OF THE DER INTEGRATION APPROACH

Chapters 4 to 6 has theoretically explicated the DER Integration Approach which aims to solve the system overall cost minimization in a hybrid generation environment. This chapter explains its software implementation and application to the same study system introduced in Chapter 3. The numerical simulation results are illustrated next. Comparison and discussion based on these results are given at the last part of this chapter.

7.1 SOFTWARE IMPLEMENTATION OF THE DER INTEGRATION APPROACH

The program is implemented in Microsoft Visual C++ 6.0 for the same reasons mentioned in Section 3.2.

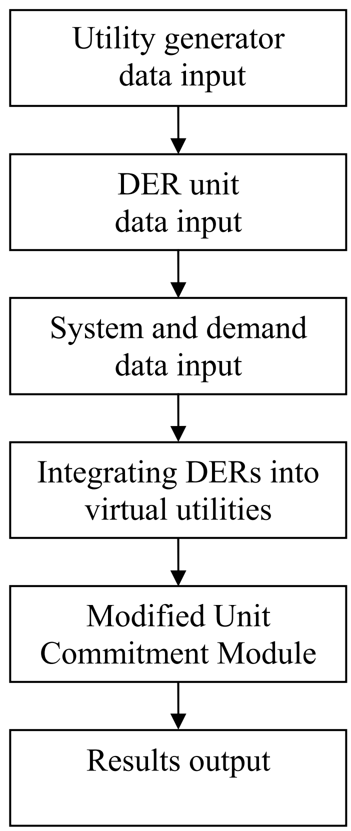

Figure 7.1 The flowchart of DER integration approach.

The flowchart of the main program is shown in Figure 7.1. In the first three modules of the flowchart, utility, DER, and system data are inputted into the program. The module to integrate DERs into virtual utilities is presented in Chapter 4. The modified unit commitment module is explicated in Chapter 6 and its detailed steps are illustrated in Figure 6.4. In this module, the economic dispatch problem is involved as a subproblem. $F(t)$, the total generation cost at interval t, is worked out by the modified economic dispatch explained in Chapter 5 and the computational flowchart is listed in Figure 5.2. The results are outputted at the final part of the program.

7.2 SIMULATION AND RESULTS

The program of the DER Integration Approach is applied to the study system introduced in Section 3.3. This case study is named as Case C, to distinguish from Cases A and B which were illustrated in Section 3.4. Case A gives the minimum system generation cost in the non-DER environment, while Case B solves the problem in the hybrid generation environment by applying the Iteration Approach established in Chapter 3. The same study system is applied in the 3 cases.

In Case C, a same spinning reserve of 2% is assumed as in Case B. The delivery losses are not included. The generation unit outage rate is taken into consideration in this case, i.e., each model of DERs in different virtual utilities is applied with a corresponding value of availability less than 100%, as in Table 7.1. According to the DERs' maintenance conditions, the average available rate of a same DER model may be different from one virtual utility to another.

Table 7.1 DER data of virtual utilities.

Virtual Utility	DER model	Number of DER units	availability
VU 1	Model 1	3	0.97
	Model 2	3	0.95
VU 2	Model 3	4	0.96
VU 3	Model 1	2	0.96
	Model 4	5	0.94
	Model 5	4	0.94
VU 4	Model 4	2	0.95
	Model 6	5	0.93

Table 7.2 provides the hourly output of each utility generator while Figure 7.2 depicts the total generation from the utility over the 24-hour period. The output from individual virtual utility and their summation are presented in Table 7.3 and Figure 7.3 respectively. The system generation cost and accumulative cost for each hour is summarized in Table 7.4. System lambdas in the hybrid generation environment are outlined in Figure 7.4.

Table 7.2 Hourly output (MW) of utility generator in the hybrid generation environment (Case C).

Hour	Unit1	Unit2	Unit3	Unit4	Unit5	Unit6	Unit7	Unit8
Initial state	ON	ON	--	ON	--	--	--	--
1	444	376	--	234	--	--	100	--
2	416	351	--	216	--	--	100	--
3	395	331	--	202	--	--	100	--
4	388	324	--	197	--	--	100	--
5	418	352	--	217	--	--	100	--
6	432	365	--	226	--	--	100	--
7	424	358	226	221	--	--	100	--
8	434	367	233	228	168	--	100	--
9	479	409	262	257	192	--	100	--
10	500	443	286	281	213	--	100	--
11	500	469	304	300	228	--	100	--
12	488	417	268	263	198	--	100	--
13	477	407	261	256	191	--	100	--
14	450	382	243	238	177	--	100	--
15	439	372	236	231	171	--	100	--
16	435	368	233	228	168	--	100	--
17	434	367	233	228	168	--	100	--
18	448	380	242	237	176	--	100	--
19	461	392	251	245	183	--	100	--
20	495	424	273	268	201	--	100	--
21	456	388	247	242	180	--	100	--
22	459	390	249	244	--	--	100	--
23	436	369	234	229	--	--	100	--
24	414	348	220	214	--	--	100	--

Table 7.3 Hourly output (MW) of virtual utility in the hybrid generation environment (Case C).

Hour	VU1	VU2	VU3	VU4
1	46.08	23.04	15.36	0
2	22.8	0	0	0
3	0	0	0	0
4	0	0	0	0
5	22.8	0	0	0
6	46.08	23.04	15.36	0
7	46.08	0	15.36	0
8	46.08	23.04	15.36	0
9	46.08	23.04	38.86	9.5
10	46.08	23.04	53.9	21.125
11	46.08	23.04	53.9	21.125
12	46.08	23.04	53.9	9.5
13	46.08	23.04	15.36	0
14	46.08	23.04	15.36	0
15	46.08	23.04	15.36	0
16	46.08	0	15.36	0
17	46.08	23.04	15.36	0
18	46.08	23.04	15.36	0
19	46.08	23.04	15.36	0
20	46.08	23.04	53.9	21.125
21	46.08	23.04	15.36	0
22	46.08	23.04	15.36	0
23	46.08	0	15.36	0
24	0	0	0	0

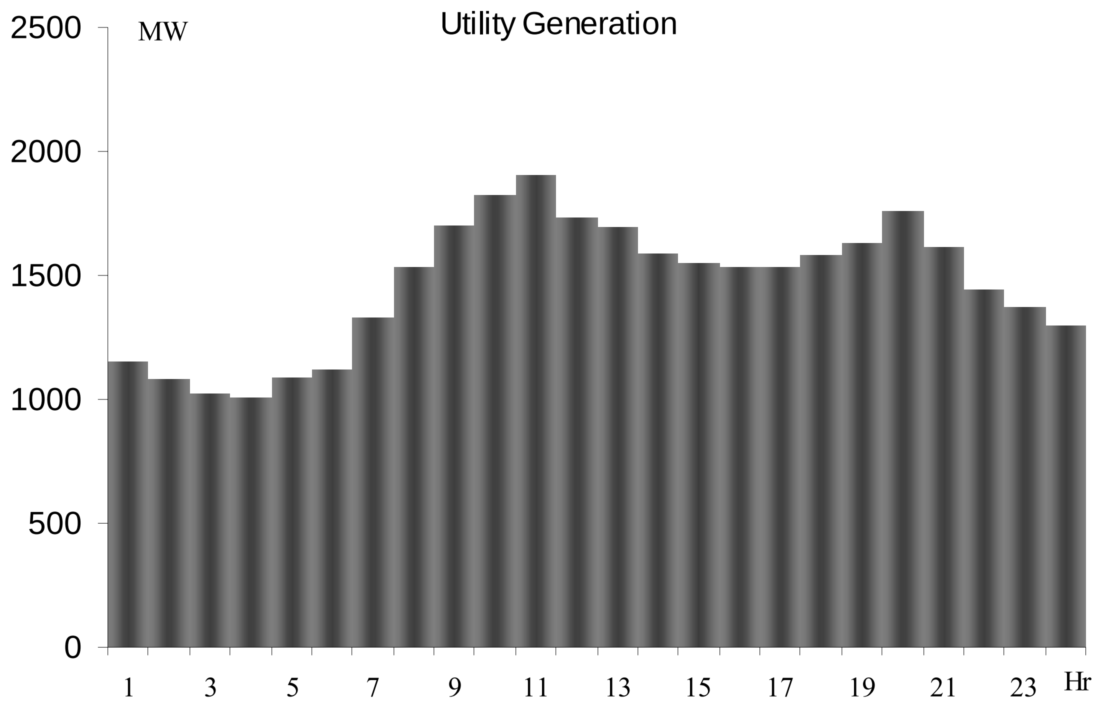

Figure 7.2 Total utility output over 24-hour period in the hybrid generation environment (Case C).

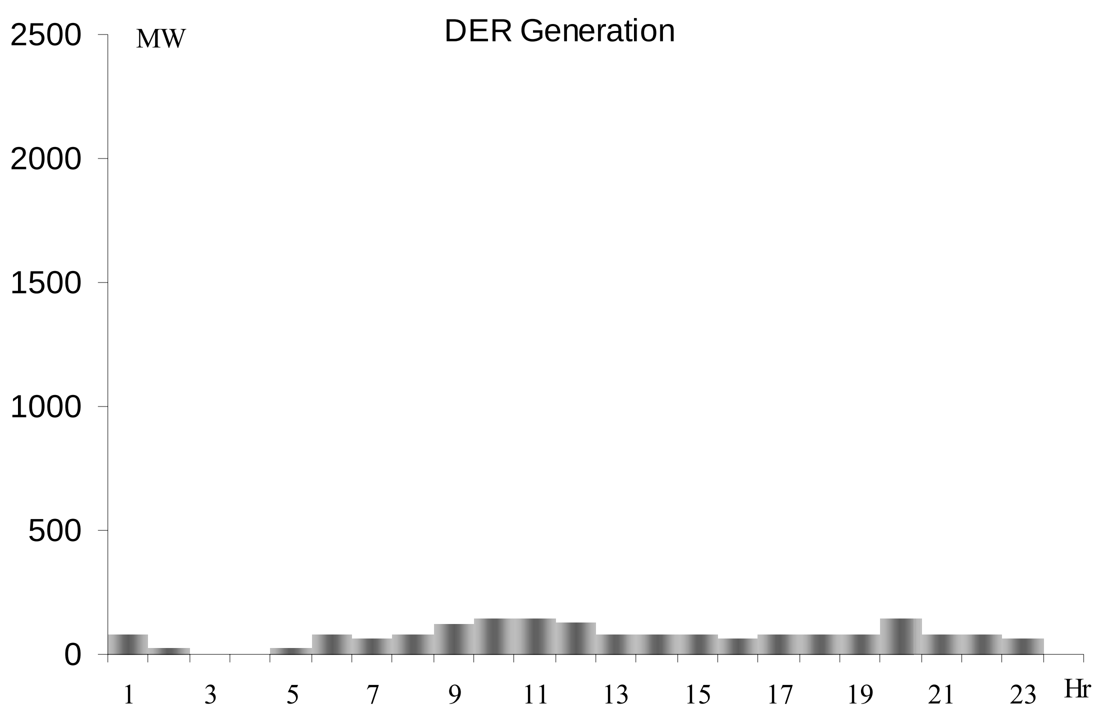

Figure 7.3 Total DER output over 24-hour period in the hybrid generation environment (Case C).

Table 7.4 The system hourly generation and accumulative costs (Case C).

Hour	Generation Cost ($)	Accumulative Cost ($)
1	121353.8	123153.8
2	107096.1	230249.9
3	99096.8	329346.6
4	97148.2	426494.8
5	107620.7	534115.4
6	118016.2	652131.7
7	137589.9	796221.6
8	161745.1	961966.8
9	183809.9	1145776.6
10	200898.7	1346675.4
11	210168.5	1556843.9
12	189497.2	1746341.1
13	179382.5	1925723.6
14	168327.7	2094051.3
15	163989.9	2258041.0
16	159613.6	2417654.5
17	161850.6	2579505.3
18	167458.6	2746963.8
19	172917.8	2919881.5
20	193765.3	3113646.8
21	170726.8	3284373.5
22	152153.5	3436527.0
23	141656.6	3578183.5
24	127621.0	3705804.5

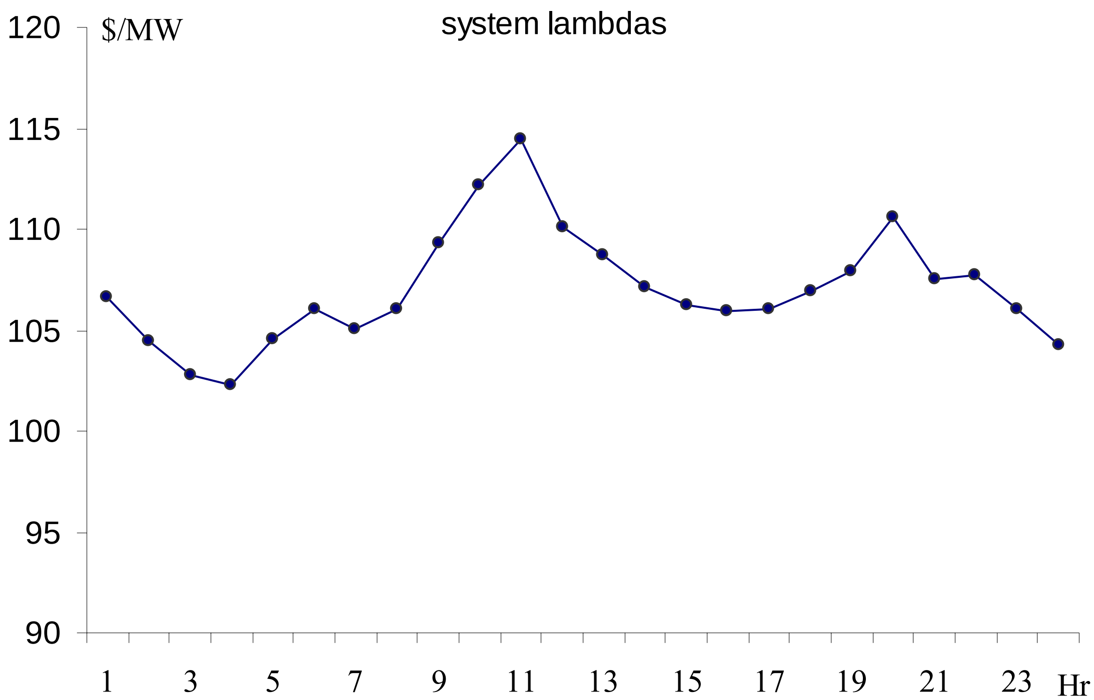

Figure 7.4 The outline of system lambdas for the Non-DER environment (Case C).

Because of the DERs' capability of peak and spike shaving, the load curve of the utility is flatter in Case C than in Case A. As illustrated in Figure 7.2, the utility generation peak is now 1901.9MW, lower than 2046MW in Case A, and the utility load factor is 0.769, higher than 0.752 in Case A. A higher load factor means a flatter load curve.

7.3 CASES COMPARISON

The final results of Case C are summarized in Table 7.5. The results of Cases A and B from Chapter 3 are also included for comparison. Besides, Cases D is brought in to compare performances of the Iteration Approach and DER Integration Approach. The conditions of Case D are almost same as those of Case C except that the availabilities of all DERs are assumed to be 100% in Case D. This means the DER outage rate is not taken into consideration. The results of Case D are achieved by the DER Integration Approach and compared with those of Case B, which are achieved by the Iteration Approach.

7.3.1 Case A vs. Case C

From Table 7.5, the virtual utilities generate 5.0% of the total 36932 MWh energy demand over the 24-hour period in Case C. Deducting the generation cost ($194427) from the revenue received from the utility ($199722), they make a profit of $5295 at a benefit/cost ratio of 1.027.

In Case C, the total utility cost is $3705805, which equals the total of the generation cost, $3506082, and the price paid to virtual utilities, $199722. It is $11950, or 0.32% lower compared to Case A. This means that the participation of DER in power generation also reduces the utility cost.

From an overall viewpoint, the power system’s total generation cost in Case C is $3700509, consisting of $3506082 of utility generation cost and $194427 of DER generation cost. It is 0.5% lower than that of Case A. This means that in a hybrid generation environment, power is generated in a more efficient way so that less fuel is burned out than in a non-DER environment. The overall social welfare is promoted.

Table 7.5 The results of simulations for Cases A, B, C, and D.

Categories	Items	Case A	Case B	Case C	Case D
Utility	Utility Generation (MWh)	36932	34688.5	35090	34919.5
	Utility Generation Cost($)	3717755	3462754	3506082	3487554
	Average Utility Generation Cost ($/MWh)	100.66	99.82	99.92	99.87
	Electricity purchased from Virtual Utilities (MWh)	--	2243.5	1842	2012.5
	Price Paid to Virtual Utilities ($)	--	243550	199722	218070
	Total Load (MWh)	36932	36932	36932	36932
	Total Utility Cost ($)	3717755	3706304	3705805	3705624
	Average Utility Cost ($/MWh)	100.66	100.35	100.34	100.34
Virtual Utility	DER Generation (MWh)	--	2243.5	1842	2012.5
	DER Generation Cost ($)	--	236980	194427	212438
	Price Paid by Utility($)	--	243550	199722	218070
	DER Profit ($)	--	6570	5295	5632
Overall	Total Load (MWh)	36932	36932	36932	36932
	Total Generation Cost($)	3717755	3699734	3700509	3699992
	Average Load Cost ($/MWh)	100.66	100.18	100.20	100.18

Case A: By conventional approach (non-DER environment).

Case B: By Iteration Approach (assuming all DER availabilities are 100%).

Case C: By DER Integration Approach (assuming DER availabilities are specified values).

Case D: By DER Integration Approach (assuming all DER availabilities are 100%).

7.3.2 Case B vs. Case D

Cases B and D employ different approaches but both neglect the DER outage rate. Their results are very close and both cases illustrate the positive economic impact of DERs on the power system.

Due to its mono-objective of utility cost minimization, which consists of the utility generation cost and the price paid to DERs, the DER Integration Approach biases slightly towards the utility compared to the Iteration Approach which applies a framework of multi-objective. In this study system, the DER Integration Approach finds out the global minimum value of the utility cost, \$3705624 in Case D, which is 0.02% lower than that in Case B.

The Iteration Approach is a multi-objective framework: different modules have respective objectives and their coordination is achieved between the utility and DER modules. The utility generation cost is minimized within the Utility Module and compromised by the iterative computations between modules. As a result, the achieved utility cost in Case B is a local optimum value. However, Case B slightly favors DER operators, who make more profits than in Case D.

Combining the benefits of the utility and DER operators together, both approaches are efficient to promote the overall profits. As illustrated in Table 7.5, the average electricity costs are same in Cases B and D. After averaging the utility and DERs generation costs, one unit of electricity costs \$100.18, 0.5% lower than that of Case A, a non-DER system.

The Iteration Approach takes about two minutes to work out the solution while the DER Integration Approach only takes a few seconds in the same computer, indicating the former approach is computationally less efficient compared to the latter one.

7.3.3 Case C vs. Case D

The results of D are slightly more optimistic than those of Case C because the availability of DERs, as discussed in Section 4.3, is taken into consideration in Case C. This means that in Case C, the virtual utilities integrated by DERs are accordingly degraded and averagely generate less power than in Case D, as long as other conditions remain the same. The simulation in Case C is closer to what is happening in the real world.

To have a clear view of the impact of DER availabilities, the family of Case E is demonstrated and its results are summarized in Table 7.6. In Case E, the availabilities of every DER are assumed to be same, escalating from 0 to 100% with the step size being 10%. For easy comparison, the spinning reserve coefficient is considered to be 1.05 as the DER availability is greater than or equal to 60%, or 1.02 otherwise. Other conditions are same as Case C. Results are achieved by the DER Integration Approach.

From Table 7.6, as the availability of DER escalates gradually, DERs become to generate more power and make more profits, while the utility is decreasing its overall cost. The total utility costs and DER profits under different DER availability situations are respectively plotted in Figure 7.5 and Figure 7.6, which clearly demonstrate their changing trends.

When the availabilities of all DERs are zero, no DER is available. The study system is actually simulating the non-DER environment of Case A. As illustrated in Table 7.6, the results achieved by the DER Integration Approach are same as those of Case A, which are achieved by applying the conventional approach. Therefore in both Figure 7.5 and Figure 7.6, the data points of Case A coincide with the data points of Case E with zero DER availability.

As the DER availability reaches 100%, Case E becomes identical to Case D. In that case, DERs make most profits and the utility achieves its least cost among the situations of different DER availability in Case E. The results of Case B, achieved by the Iteration Approach, are also plotted in Figure 7.5 and Figure 7.6. The differences between Cases B and D (identical to Case E with 100% DER availability) are discussed in section 7.3.2.

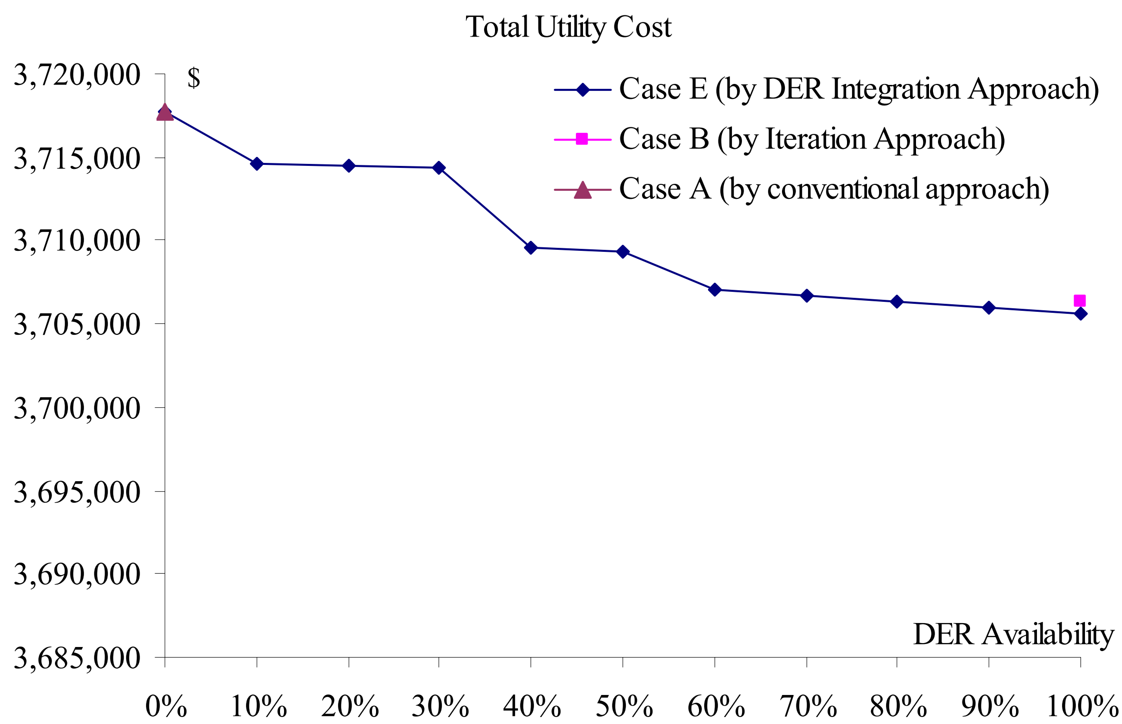

Figure 7.5 Total utility costs under different DER availabilities (Cases A, B, and E).

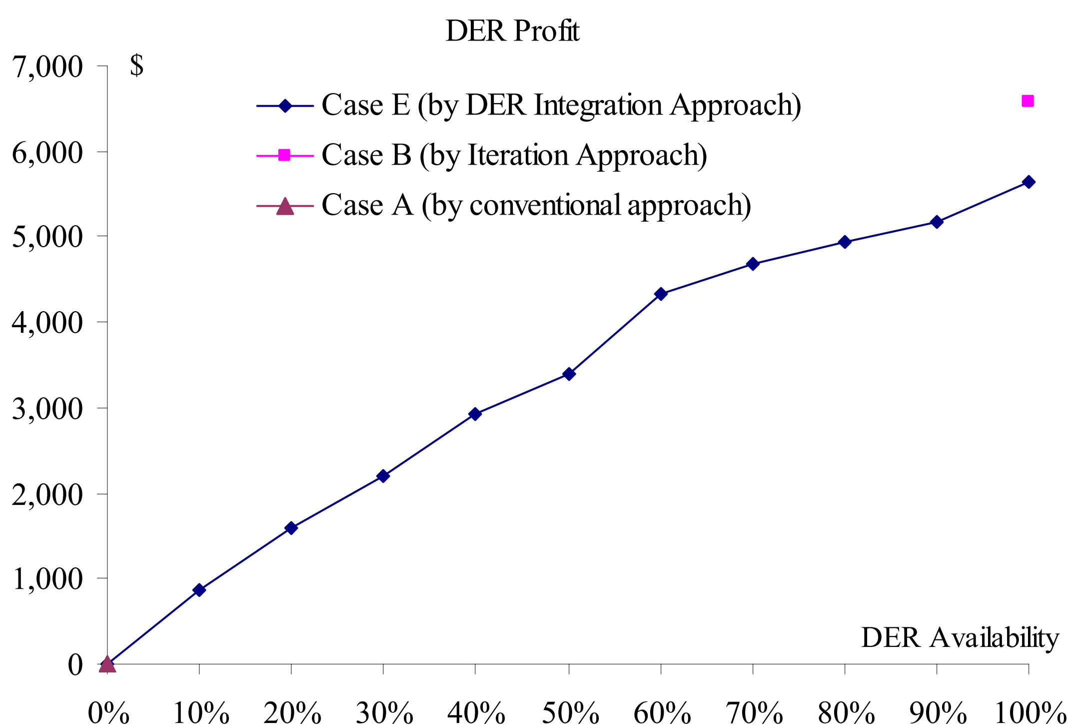

Figure 7.6 Total DER Profit under different DER availabilities (Cases A, B, and E).

Table 7.6 The results of simulations for Case E.

Availability of DER		0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Utility	Utility Generation (MWh)	36932	36697	36475	36260	36076	35880	35710	35507	35303	35164	34919
	Utility Generation Cost($)	3717755	3688821	3664522	3641107	3616123	3594687	3573622	3551407	3529242	3514097	3487554
	Average Utility Generation Cost ($/MWh)	100.66	100.52	100.47	100.42	100.24	100.19	100.07	100.02	99.97	99.93	99.87
	Electricity purchased from Virtual Utilities (MWh)	0	235	457	672	856	1052	1222	1425	1629	1768	2013
	Price Paid to Virtual Utilities ($)	0	25793	50000	73277	93467	114665	133458	155327	177100	191906	218070
	Total Load (MWh)	36932	36932	36932	36932	36932	36932	36932	36932	36932	36932	36932
	Total Utility Cost ($)	3717755	3714614	3714522	3714384	3709590	3709352	3707080	3706734	3706342	3706003	3705624
	Average Utility Cost ($/MWh)	100.66	100.58	100.58	100.57	100.44	100.44	100.38	100.37	100.36	100.35	100.34
Virtual Utility	DER Generation (MWh)	0	235	457	672	856	1052	1222	1425	1629	1768	2013
	DER Generation Cost ($)	0	24937	48413	71066	90536	111269	129128	150649	172171	186739	212438
	Price Paid by Utility($)	0	25793	50000	73277	93467	114665	133458	155327	177100	191907	218070
	DER Profit ($)	0	856	1587	2211	2931	3396	4330	4678	4929	5168	5632
Overall	Total Load (MWh)	36932	36932	36932	36932	36932	36932	36932	36932	36932	36932	36932
	Total Generation Cost($)	3717755	3713758	3712935	3712173	3706659	3705956	3702750	3702056	3701413	3700836	3699992
	Average Load Cost ($/MWh)	100.66	100.56	100.53	100.51	100.36	100.35	100.26	100.24	100.22	100.21	100.18

Chapter 8 CONCLUSIONS AND RECOMMENDATIONS

This chapter concludes the study on the overall cost minimization for a hybrid generation power system presented in the previous chapters. Based on the results of this research, conclusions are summarized in this chapter, followed by recommendations for future researches.

8.1 CONCLUSIONS

This thesis does not attempt to provide the “last word” in the overall cost minimization for a hybrid generation power system, nor does it attempt to provide very accurate numerical results to describe the reality precisely. Rather, the main contributions of this thesis are to provide an innovative perspective to think of such a complex system problem, to make practical contributions by developing explorative approaches toward perfect solutions of such a problem, and to provide first-cut numerical results with which future results can be compared.

Based on the discussions in the previous chapters, the conclusions are summarized:

1. Two improved approaches, namely the Iteration approach and the DER Integration Approach, have been established in this thesis to solve the overall cost minimization for a hybrid generation power system. The simulation results demonstrate that these approaches work out an optimal system operation solution over a long period, such as 24 hours. The optimal solution reduces the expenditures for the utility and brings profits to the DER operators. The interests of both utility and DERs are protected, and their outputs coordinated, in these approaches.

2. The simulation results demonstrate that introducing DERs into the generation competition brings about a positive impact on the power system and benefits all the parties with the DERs making profits, the utility lowering its cost, and the consumer's demands being satisfied. Besides, the DERs' capability of load peak- and spike-shaving enable them to modify the utility load shape, achieving certain advantages, such as, increase of system reliability, avoidance of expensive utility generation additions, and providing flexibility in the utility resource planning process.

3. The DER Integration Approach is computationally more efficient than the Iteration approach. In addition, it takes into account the availability of DERs to simulate the generation unit outage rate in the real world, and hence its simulation results are closer to reality than those of the Iteration Approach. However, the programming of the DER Integration Approach is relatively more complicated and difficult than that of the Iteration Approach.

4. The evolution of the power system from a non-DER environment to a hybrid generation environment is still in progress. The benefits enjoyed by all the parties are not drastic but moderate, as illustrated in the comparison of the simulation results (Sections 3.4 and 7.2). This is mainly because although the DER technologies are developing quickly, these small generators cannot, currently, win over large utility generators in base generation. They are now better off supplying the peak and spike loads. As the DER technology innovation continues its fast

pace of development, the DERs are expected to be more economical and competitive, and all the parties will see greater benefits in the near future.

8.2 RECOMMENDATIONS FOR FUTURE RESEARCHES

Although much time and effort have been put into developing the approaches to achieve overall cost minimization in a hybrid generation system, there is still space for future expansion. The recommendations for future researches are summarized below:

1. As discussed in Chapter 2, DERs can offer auxiliary services such as providing reactive power and voltage support. These services can be quantified as components of the electricity buy-back prices to encourage DERs' more active engagement in the power system.

2. With the rapid development of communication technologies, it becomes possible for big electricity consumers to see time-varying electricity prices, which may not necessarily be the same as, but are definitely related to, the buy-back prices the independent power producers see. The responses from consumers, such as load shifting, energy storage, and forward contract, will modify the system load demand curve. These consumer responses, which make the customer module more complicated, can be studied in the future researches.

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Appendix NUMERICAL CONVOLUTION USING RECURSIVE TECHNIQUE

As introduced in Chapter 4, the total output P_k^R of a virtual utility k is achieved by summing up the outputs of all J_k DERs in that virtual utility as in equation (4.7), which is rewritten here for clarity.

$$P_k^R = \sum_{j \in J_k} P_j^R \tag{A.1}$$

where P_j^R , the output of DER j, is a random variable as described in Section 4.3. P_k^R , as a summation of random variables in (A.1), is a random variable too. This means that the generation of virtual utilities is a stochastic process. In this thesis the superscript R of a variable is used to denote that variable as a random variable.

Knowing the probability density function (PDF) of each P_j^R from equation (4.4) in Chapter 4 and assuming they are independent of each other, the PDF of P_k^R can be derived by applying a numerical convolution using recursive technique.

With the recursive technique, the summation of equation (A.1) is implemented step by step, i.e. the output of DER is added into P_k^R once by a single unit. Assume currently, $P_k^{R(u)}$, the summation of total u DERs, and $f_k^{(u)}(x)$, the PDF of $P_k^{R(u)}$, have been achieved, where x is the output of $P_k^{R(u)}$. The next step is to add in the (u+1)th DER. To generalize the formula, it is taken into consideration that the (u+1)th DER is an "N-state" unit, i.e. its output has N possibilities, as in state n the output is $O_{u+1}(n)$ and the corresponding probability is $p_{u+1}(n)$. The summation of the output of the total (u+1) DERs is $P_k^{R(u+1)}$, and its PDF $f_k^{(u+1)}(x)$ can be achieved by:

$$f_k^{(u+1)}(x) = \sum_{n=1}^{N} p_{u+1}(n) f_k^{(u)}(x - O_{u+1}(n)) \tag{A.2}$$

After recursively using the numerical convolution (J_k -1) times, the output of all the J_k DERs in virtual utility k are summed up as $P_k^{R(J_k)}$ and its PDF is achieved as $f_k^{(J_k)}(x)$. They are respectively denoted as P_k^R, the overall output of virtual utility k, and $f_k(x)$, the PDF of P_k^R, for simplicity.